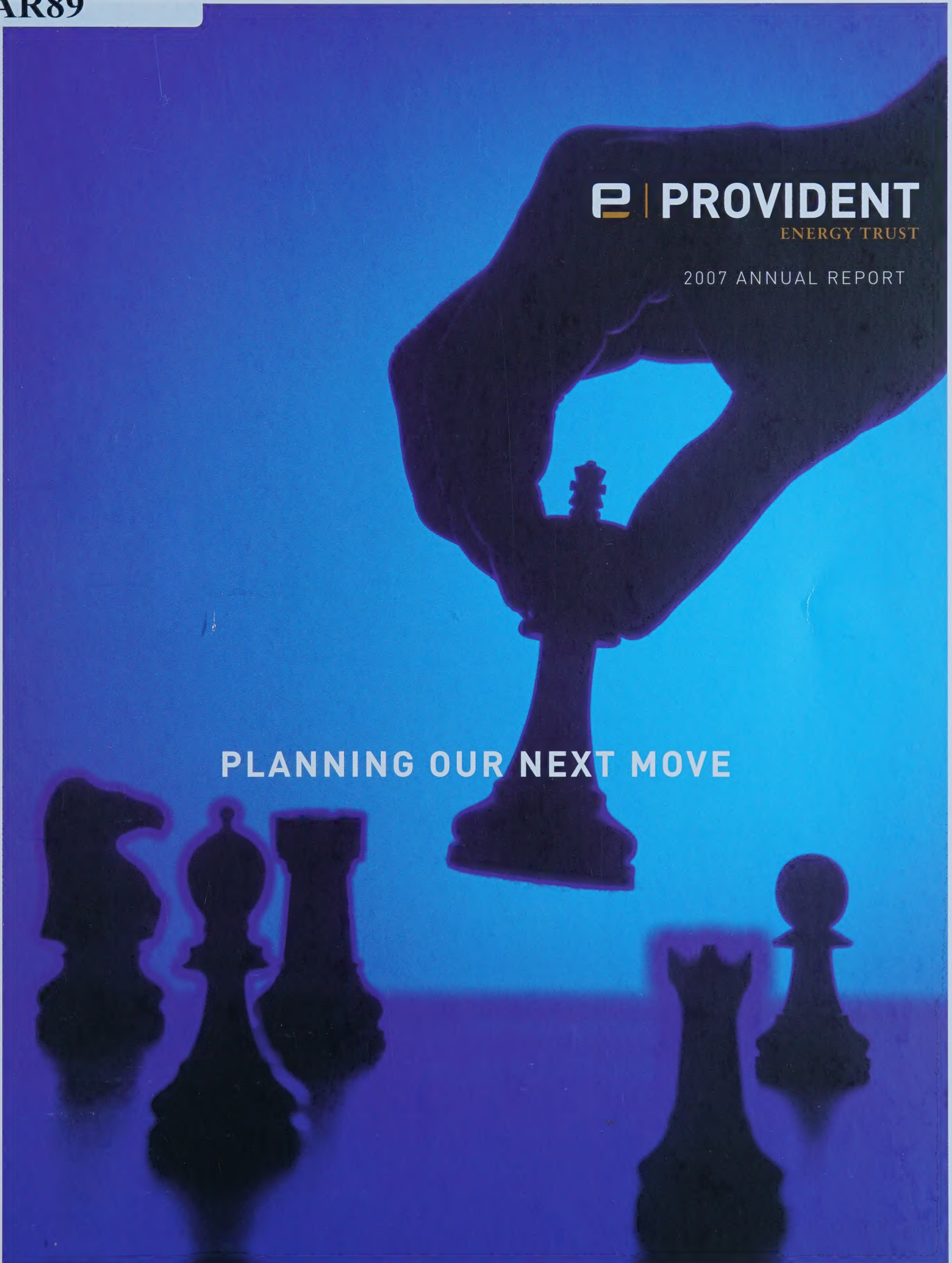
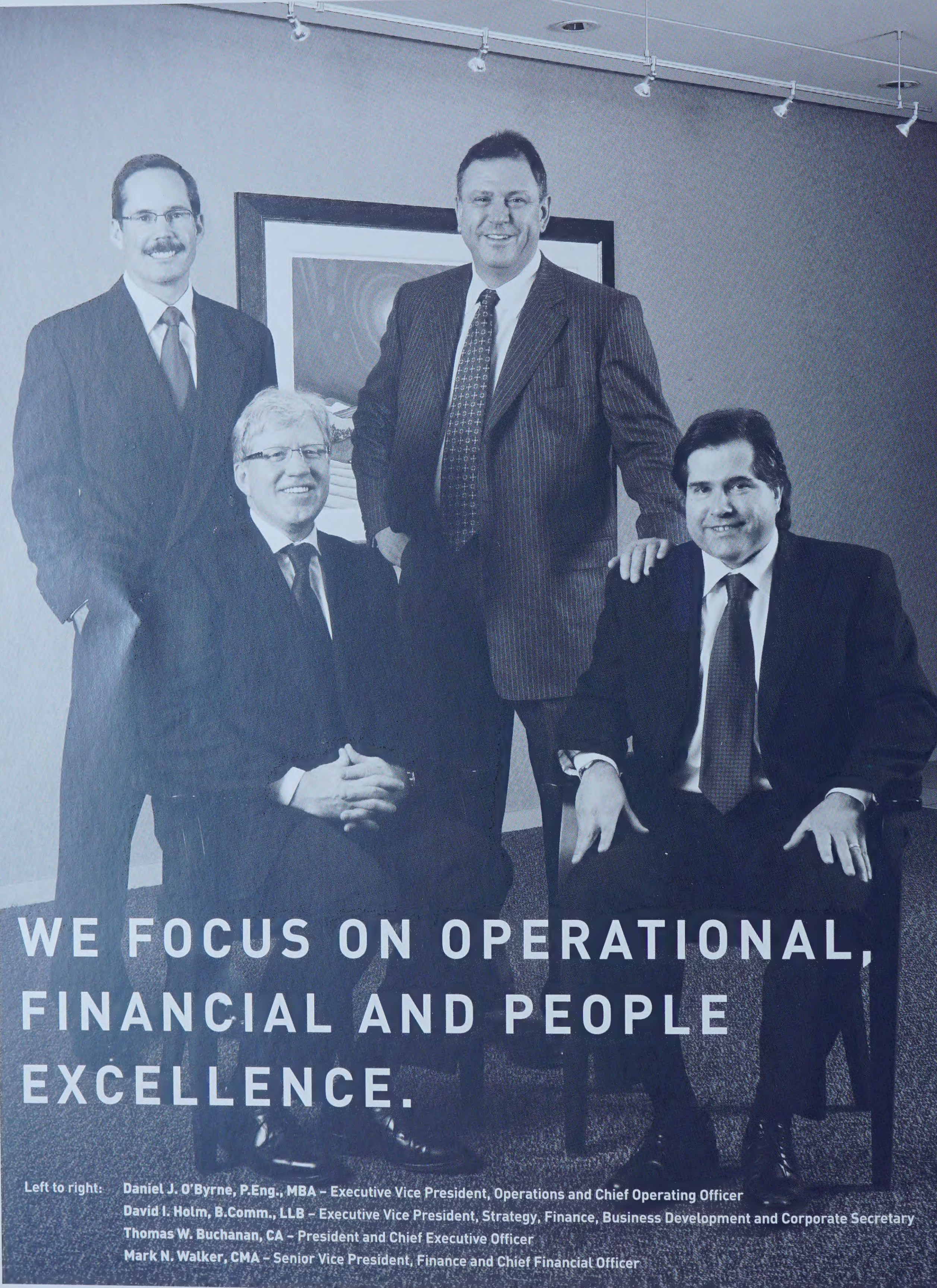

PROVIDENT
ENERGY TRUST
2007 ANNUAL REPORT
PLANNING OUR NEXT MOVE



Left to right: Daniel J. O'Byrne, P.Eng., MBA – Executive Vice President, Operations and Chief Operating Officer
David I. Holm, B.Comm., LLB – Executive Vice President, Strategy, Finance, Business Development and Corporate Secretary
Thomas W. Buchanan, CA – President and Chief Executive Officer
Mark N. Walker, CMA – Senior Vice President, Finance and Chief Financial Officer

$12.39

PER UNIT

distributed since inception in 2001 (approximately US$9.31 per unit to U.S. investors). Representing an overall total return of 162%.

2007 marked the fourth full year of stable cash distributions for Provident unitholders, at CDN$0.12 per month, or $1.44 per year. As well as high cash yields, Provident has generated excellent long-term value for investors.

WE OPERATE HIGH-QUALITY ENERGY ASSETS TO GENERATE STABLE CASH DISTRIBUTIONS AND LONG-TERM VALUE FOR INVESTORS.

Contents

2007 PERFORMANCE

CONSOLIDATED FINANCIAL HIGHLIGHTS
YEAR ENDED DECEMBER 31

Canadian dollars (000s except per unit data)	2007	2006	% Change
Revenue (net of royalties and financial derivative instruments)	**$2,167,276**	$2,187,253	(1)
Funds flow from COGP operations [1]	**$ 204,252**	$ 185,328	10
Funds flow from USOGP operations [1][3]	**85,571**	62,970	36
Funds flow from Midstream operations [1]	**178,432**	184,366	(3)
Total funds flow from operations [1]	**$ 468,255**	$ 432,664	8
Per weighted average unit – basic and diluted [2]	**$ 2.04**	$ 2.20	(7)
Distributions to unitholders	**$ 333,352**	$ 283,465	18
Per unit	**$ 1.44**	$ 1.44	–
Percent of funds flow from operations paid out as declared distributions [3]	**77%**	67%	15
Net income (loss) [4]	**$ 30,434**	$ 140,920	(78)
Per weighted average unit – basic and diluted [2]	**$ 0.13**	$ 0.72	(82)
Capital expenditures	**$ 247,122**	$ 190,433	30
Capitol Energy acquisition	**$ 467,495**	$ –	
Triwest Energy acquisition	**$ 78,877**	$ –	
USOGP natural gas asset acquisition	**$1,464,213**	$ –	
Oil and gas property acquisitions, net	**$ 265,201**	$ 481,625	
Weighted average trust units outstanding (000s)			
– Basic	**229,939**	196,627	17
– Diluted [2]	**229,939**	196,914	17

As at December 31 Canadian dollars (000s)	2007	2006	% Change
Capitalization			
Long-term debt	**$1,549,272**	$ 988,785	57
Unitholders' equity	**$1,708,665**	$1,542,974	11

(1) Represents cash flow from operations before changes in working capital and site restoration expenditures.
(2) Includes dilutive impact of unit options, exchangeable shares and convertible debentures.
(3) Calculated as distributions to unitholders divided by funds flow from operations less distributions to non-controlling interests of $35.8 million (2006 – $6.5 million).
(4) Net income (loss) for the year ended December 31, 2007 includes a future income tax charge of $88.4 million relating to the enactment of Bill C-52, Budget Implementation Act 2007 by the Canadian government.

CONSOLIDATED OPERATIONAL HIGHLIGHTS
YEAR ENDED DECEMBER 31

	2007	2006	% Change
Oil and gas production			
Daily production			
Light/medium crude oil (bpd)	**17,433**	14,114	24
Heavy oil (bpd)	**1,921**	2,057	(7)
Natural gas liquids (bpd)	**1,421**	1,419	–
Natural gas (mcfpd)	**107,151**	84,891	26
Oil equivalent (boed)[1]	**38,633**	31,739	22
Average realized price (before realized financial derivative instruments)			
Light/medium crude oil ($/bbl)	**$ 63.48**	$ 60.32	5
Heavy oil ($/bbl)	**$ 41.85**	$ 36.80	14
Corporate oil blend ($/bbl)	**$ 61.29**	$ 57.33	7
Natural gas liquids ($/bbl)	**$ 51.90**	$ 51.98	–
Natural gas ($/mcf)	**$ 6.53**	$ 6.66	(2)
Oil equivalent ($/boe)[1]	**$ 50.64**	$ 49.35	3
Field netback (before realized financial derivative instruments) ($/boe)	**$ 28.24**	$ 27.93	1
Field netback (including realized financial derivative instruments) ($/boe)	**$ 27.79**	$ 28.09	(1)
Midstream			
Midstream NGL sales volumes (bpd)	**120,785**	115,354	5
EBITDA (000s)[2]	**$ 225,675**	$ 219,631	3

(1) Provident reports oil equivalent production converting natural gas to oil on a 6:1 basis.

(2) EBITDA is earnings before interest, taxes, depletion, depreciation, accretion and other non-cash items. See "Reconciliation of non-GAAP measures" in Management's Discussion and Analysis.

BOLD MOVES 2007

OUR MOVES

Provident has a history of building the business through strategic advances, proved to add substantial long-term value. The initial conversion into an energy trust in 2001, the entry into the Midstream business in 2003 and the decision to spin off part of the U.S. business as a public entity are all good examples of creating value. Our current focus remains the same, as Provident moves to position its businesses for success given the legislated changes to the income trust sector in Canada.

UPSTREAM CANADA (COGP)

Two important acquisitions in 2007 built on the successful Rainbow acquisition in 2006 to strengthen the Canadian oil and gas production business and to position it for the future. Over the past two years, the Canadian upstream business unit has increased production and reserves, extended the reserve life index, increased netbacks, and greatly increased the inventory of identified drilling locations.

In June 2007, Provident acquired Capitol Energy Resources for net cash consideration of $467 million, which included an exceptional long-life oil resource play at Dixonville, Alberta. Dixonville is a large oil pool still in its early stages of development, with production growth expected through 2009. The acquisition increased Provident's production per unit, reserves per unit and cash flow per unit, while reducing per barrel operating costs. In December, Provident closed the $79 million Triwest Energy acquisition, adding high-quality low-cost oil assets to its existing operations in Southeast Saskatchewan.

UPSTREAM U.S. (USOGP)

In the first half of 2007, BreitBurn Energy Partners, L.P. completed three accretive acquisitions of long-life oil assets, in Texas, Florida and California for a total of $215 million. Then in November, the MLP completed a $1.5 billion acquisition of long-life natural gas producing assets located primarily in Michigan, from Quicksilver Resources. This acquisition nearly tripled the MLP reserves base, transforming the MLP into a balanced oil and gas producer and one of the largest gas producers in the Antrim Shale region.

MIDSTREAM

The Midstream business continued to capitalize on the synergies provided by our major acquisition in late 2005 that made Provident the second-largest integrated natural gas liquids (NGL) business in Canada. Recent growth projects include completion of the condensate rail offloading and storage facility at Redwater, and beginning work on two new 600,000-barrel underground liquids storage caverns, adding to our existing 8.5 million barrels of underground storage. Provident is well positioned to take a lead role in providing key essential services to the oil sands producers in Alberta.

COMMUNITY INVESTMENT

Provident's longstanding positive relationship with the town of Redwater, Alberta (site of one of Provident's midstream fractionation facility) culminated in 2007 with a legacy commitment of $0.5 million to support the refurbishment of the town's aging recreation complex. Executives joined community leaders and local residents in September 2007 to celebrate the official opening of "Provident Place".

THE NEXT MOVES

THOMAS W. BUCHANAN
President and Chief Executive Officer

Provident had a dynamic year of growth achieving strong operating and financial performance in spite of the political and economic changes we encountered in 2007. External events – the aftermath of the trust taxation announcement, the new Alberta royalty regime, the tight equity and debt capital markets and the volatile stock markets provided challenges to our long-term business plan. Our priorities for 2008 are to continue to deliver consistent performance while addressing the broader strategic questions created by those external events.

2007 was an excellent year operationally. We met or exceeded all of the guidance we issued publicly, and achieved our own internal targets for the year. We generated record cash flow of $468 million, and delivered another full year of stable monthly cash distributions to our unitholders. Our diverse portfolio – designed to withstand commodity price cycles – effectively moderated the impact of declining natural gas prices and the rising Canadian dollar. We completed significant oil-weighted acquisitions of high-quality assets in our Canadian upstream business. Our 2008 capital program illustrates our flexibility with a quality suite of internal opportunities in both our upstream and midstream businesses to draw from.

As an executive team, we strive to build the business for long-term value. Cash yields and total returns for Provident investors over time have been excellent. With our high-quality energy assets and our outstanding team of people, we remain confident that Provident will continue to deliver long-term unitholder value.

However, Provident faces an interesting set of challenges over the next year, with volatile capital markets and the uncertainty in the trust sector caused by the Government of Canada's decision to restrict the growth of trusts today and tax trusts beginning in 2011. We are taking a strategic and measured approach to addressing these challenges, as we seek to unlock the full value of our portfolio of high-quality energy assets. We're making good progress on defining an exciting new future for Provident.

STRATEGIC DIRECTION: UNLOCKING THE VALUE OF THE ASSETS

In 2007 we were affected by a volatile business environment. While U.S. crude oil prices surged over the year from a low of $55 per barrel to a high that approached $100 per barrel, that gain was offset by a Canadian dollar that reached record highs against the U.S. dollar and weak natural gas prices. The announcement of a new higher royalty regime effective 2009, in our home province of Alberta, will have a detrimental impact on capital spending and return on capital in the sector. For Provident, the royalty impact is mitigated by our diversified business model. Finally, the tightening of global credit markets and the general market uncertainty that we saw late in 2007 affect us as access to capital becomes more challenging.

Provident's diversification enabled us to maintain consistent cash distributions in 2007. However, Provident's market valuation

"WE ARE TAKING A STRATEGIC APPROACH AS WE SEEK TO UNLOCK THE FULL VALUE OF OUR PORTFOLIO OF HIGH-QUALITY ENERGY ASSETS."

lagged our operating and financial performance, reinforcing our belief that the full value of Provident's component businesses is not being reflected in our unit price. As a management team, our market performance adds impetus to our normal course strategic planning processes and requires us to consider alternatives to determine whether our valuation can be enhanced for our component businesses.

On February 5, 2008, we took a significant and strategic first step in unlocking value and preparing for 2011 by announcing our intention to enter into a strategic sales process for our U.S. oil and gas business. By virtue of our decision to undertake the Initial Public Offering (IPO) of BreitBurn Energy Partners, L.P. (MLP) in October 2006, we effectively converted our holdings in the MLP into an investment rather than a strategic growth vehicle. As a result, we now have the opportunity to realize a potential gain on our original investment in our U.S. assets. Monetizing our investment in our U.S. oil and gas business would remove a complex aspect of Provident's overall corporate structure and enhance our strategic flexibility.

A major priority in 2008 is to complete the analysis around how best to optimize the structure of Provident's business units beyond 2011. This is a complex exercise, driven by a number of key objectives, including to:

- optimize business performance and facilitating growth;
- assess the feasibility of alternative structures;
- improve overall access to capital and finance growth; and
- capture and protect value for our unitholders.

The work we have done analyzing the tax and financial implications of various scenarios will assist us in our work to create the optimal structure for Provident and its component business.

OPERATIONS REVIEW: THE FOCUS ON PERFORMANCE DELIVERS

In my 2006 annual report letter, I wrote that "operationally, our focus in 2007 will be on execution." We achieved notable success in this initiative. We are working hard to sharpen our execution ability to ensure we achieve the full potential of our assets across our businesses. To measure our progress, we benchmark ourselves on a set of key operational performance indicators against peer companies in both the upstream and midstream sectors of our industry.

Canadian Oil and Gas Production

In our upstream business, we saw excellent improvement in 2007 on such key performance drivers as operating costs, finding and development (F&D) costs, and reserve life, when measured against our Canadian energy trust peers. We still have further to go to reach best-in-class levels on some of these measures, and execution continues to be a strong focus in 2008.

In the Canadian upstream business, the biggest news of 2007 was the $467 million (net cash consideration) acquisition in June of Capitol Energy, with its exciting Dixonville oil play in northwestern Alberta. Dixonville will be a big part of Provident's future. It is a very large oil pool of approximately 263 million barrels of original oil-in-place

"PROVIDENT'S DIVERSIFICATION ENABLED US TO MAINTAIN CONSISTENT CASH DISTRIBUTIONS IN 2007 IN SPITE OF THE VOLATILE BUSINESS ENVIRONMENT."

that will be recovered through horizontal drilling and a waterflood program. The Dixonville assets have a reserve life index of 18.9 years, and we anticipate production to increase through 2009 as we drill further wells and expand the waterflood.

Late in 2007, we completed the smaller $79 million Triwest acquisition, adding excellent oil assets located in Southeast Saskatchewan. Like Dixonville, production from the Triwest assets is still growing. We are optimistic that our Southeast Saskatchewan team will be as successful with these new wells and drilling locations as they have been with our existing operations in the region. Production from the new assets reached 1,550 boed by the end of 2007, already up 19 percent from the production rate at the time we announced the acquisition.

Between Dixonville, Triwest and the Rainbow acquisition of 2006, we have significantly strengthened our Canadian upstream asset base in the last two years, with longer reserve life, higher netbacks, more drilling opportunities and a more balanced production profile. On a stand-alone basis, Provident's Canadian upstream business has size and scale, with expected Canadian production in 2008 in the range of 26,000 to 28,000 boed. In 2007, production averaged 26,500 boed, and cash flow was $204 million.

Midstream

The Midstream business had another outstanding year in 2007, achieving EBITDA of $226 million, driven by the wide gap between relatively low natural gas prices and high oil prices (the "frac spread").

The business also performed well operationally, as the Redwater and Empress plants ran smoothly, the new rail off-loading facility at Redwater performed as expected, and the marketing team captured incremental value from our proprietary natural gas liquids barrels. Financially, we took advantage of the strong frac spread environment to continue our commodity price risk management program, under which we use financial derivative instruments to protect a profitable margin for a portion of our natural gas liquids production, ensuring a base of cash flow from our assets in the event of weaker frac spreads.

Provident's Midstream business offers exciting growth opportunities over the next few years. The biggest energy story in North America currently is the explosive growth of the Alberta oil sands. We are very well positioned, particularly through our assets at Redwater, to provide essential services to oil sands producers. Opportunities include providing condensate (a natural gas liquid) to dilute raw oil sands crude for transportation and storing and transporting oil sands-related products. Similarly, our Empress natural gas liquids extraction plant is well positioned for a long future, being the newest, most efficient of the five plants in the Empress complex.

We have now invested approximately $1.2 billion in acquiring and improving Provident's midstream assets since 2003. With EBITDA of over $200 million for the second year in a row, we are seeing a superb return on that investment. The natural gas liquids business remains highly attractive to us, and we are confident that we have among the best sets of assets and the most skilled and experienced people in the industry.

"WE LIVE BY OUR RICE VALUES – RESPECT, INTEGRITY, CREATIVITY AND EXCELLENCE."

U.S. Oil and Gas Production

Provident's U.S. business achieved impressive growth in 2007. The decision to pursue an IPO of BreitBurn Energy Partners L.P. as a master limited partnership in October 2006, proved to be timely. The strong investment market for income vehicles like the MLP pushed the unit price up by 57 percent in its first year, and took advantage of its attractive cost of capital to complete a series of accretive acquisitions.

In November, the MLP completed its largest acquisition to date, a $1.5 billion purchase of shallow natural gas producing assets primarily in Michigan's Antrim shale region. This acquisition more than doubled MLP's daily production and reserves, and transformed the MLP into a significant, diverse energy business. Because the acquisition was funded in part with new equity, Provident's ownership in the MLP has now been diluted down to approximately 22 percent.

As well as our ownership in the MLP, Provident also retains 96-plus percent ownership of BreitBurn Energy Company (BreitBurn), with long-lived oil-producing assets in California. The highlight for 2007 was bringing the Orcutt thermal oil project to the point of first production. Orcutt has the potential for production growth for many years to come.

Total production from our U.S. business – both the MLP and BreitBurn – grew from 7,700 boed in 2006 to 12,100 boed in 2007. Provident anticipates production from our U.S. business to be in the range of 24,100 to 26,300 boed in 2008. Provident's total cash invested in our U.S. assets (net of sale proceeds on the IPO of the MLP and distributions we have received back from the MLP and BreitBurn) is now approximately $100 million. Our decision to monetize our investment should capture significant value for Provident unitholders.

DEFINING A VISION FOR PROVIDENT'S FUTURE

Provident has assembled a world-class, high-quality asset base and great people in our seven-year history as a trust.

We live by our RICE values (respect, integrity, creativity and excellence), and we strive for continuous improvement in our standards of safety, environmental performance, and community relations. We also have a track record of finding innovative solutions to business challenges, and a reputation for delivering reliable high-yield investment income for our investors. Those investors, not surprisingly, are asking us what they can expect from Provident following the legislated tax changes in 2011.

Seeking strategic alternatives for our U.S. business is the first step in the process of defining a new vision for Provident. We are excited by the challenges that 2008 will bring.

On behalf of the executive leadership team, I wish to thank our employees for their continued efforts and extraordinary commitment, and our Directors for their valued guidance and support.

THOMAS W. BUCHANAN
President and Chief Executive Officer
MARCH 18, 2008


West Stoddart
Mile 73
Rainbow
Younger Plant
Fort McMurray
La Glace
Redwater
Edmonton
Calgary
Empress
Kerrobert
Cody
Superior
Sarnia
Marysville
Chicago
Conway
Lynchburg
Santa Maria
Los Angeles
BreitBurn
Mt. Belvieu
Houston
LEGEND
Provident Office
Midstream Storage
Non-proprietary Pipeline
Provident Pipeline
Midstream Extraction/ Fractionation Facility
Canadian Oil and Gas Production
U.S. Oil and Gas Production
U.S. Office

PROVIDENT OPERATING ASSETS

MIDSTREAM SNAPSHOT

2007 EBITDA ($000s)	$225,675
2007 NGL sales volume (bpd)	120,785

EMPRESS EAST

- Own varying interests in four of the six extraction plants with net capacity of 2.0 bcfd. 67.5% interest in and operator of the highest recovery, lowest cost plant.
- East-to-west pipeline access and fractionation and storage capacity at Sarnia.
  - 15,500 barrels per day of fractionation capacity.
  - 3.1 million barrels of storage capacity.

REDWATER WEST

- 100% ownership of 65,000 bpd Redwater fractionation plant.
- 43% ownership of 38,500 bpd extraction plant at Younger, BC.
- Market 100% of NGL via long-term commercial arrangements.
- Long-term access to third-party pipelines.

COMMERCIAL SERVICES

- Fee-for-service contracts for fractionation, storage, loading and marketing of NGL.
- Pipeline tariffs from LGS and Kerrobert pipelines.
- 60,000 bpd rail and truck off-loading facility.
- 835 rail cars under lease.
- 50,000 bpd debutanizer.
- 8.5 million barrels of underground storage.

UPSTREAM SNAPSHOT

2007	Combined	Canada	U.S.
EBITDA (000s)	$ 319,421	$ 221,752	$ 97,669
Average production (boed)	38,633	26,509	12,124
Year-end proved plus probable reserves (mboe) (gross)	322,408	100,820	221,589
Reserve life index (RLI)	16.9	9.7	25.4
Undeveloped land (net acres)	625,791	473,859	151,932

UPSTREAM SNAPSHOT BY AREA

2007	Canada							U.S.
	Alberta				Saskatchewan			
	Northwest	Dixonville	West Central	Southern	Southwest	Southeast	Lloydminster	USOGP
Exit production (boed)	4,453	4,033	6,575	5,189	1,562	3,120	2,812	23,946
Operating costs ($/boe)	$ 9.36	$ 4.19	$ 10.48	$ 14.18	$ 12.31	$ 11.50	$ 17.23	$ 19.04
Netback ($/boe)	$ 24.19	$ 34.91	$ 25.87	$ 21.97	$ 17.99	$ 40.24	$ 19.22	$ 34.46
CAPEX ($000)	$ 35,993	$ 43,801	$ 9,051	$ 13,079	$ 15,196	$ 5,069	$ 9,235	$ 69,009
% natural gas	93%	26%	71%	65%	82%	1%	7%	50%

THE VALUE OF OUR BUSINESSES

OUR BUSINESSES HAVE SIZE AND SCALE

Each of Provident's three business units is a sizable business in its own right. The upstream Canadian oil and gas business produces approximately 28,000 boed, making it an intermediate-sized producer. The U.S. oil and gas business now produces approximately 24,000 boed, which includes one of the largest upstream MLP companies in the U.S. The Midstream business unit is Canada's second-largest integrated natural gas liquids business.

OUR BUSINESSES HAVE FLEXIBILITY

With three strong, relatively independent businesses, Provident has both the advantage and the challenge of having many different options to consider in advance of the pending 2011 tax on Canadian income trust distributions and the growth restrictions currently in place. Provident has a track record of finding innovative solutions to challenges. Provident is assessing its strategic alternatives for its U.S. business and will continue strategic planning for its Canadian business. The overriding concern during the strategic planning exercise now underway is to protect and enhance value for unitholders.

OUR BUSINESSES HAVE QUALITY ASSETS

Each of Provident's three businesses operates high-quality assets with exciting growth prospects. Recent Canadian oil and gas business acquisitions have significantly strengthened the overall asset quality of that business. The U.S. business operates very long-life assets, including the high-potential Orcutt thermal project that is being commissioned. The Midstream business operates the most efficient plant in the Empress extraction complex as well as the best-in-class Redwater facility, and is one of only two natural gas liquids producers with pipeline access to ship NGL products from west to east.

OUR BUSINESSES HAVE LONG-LIFE VALUE

Provident has worked to build a sustainable business, with an overall economic life index of approximately 18.5 years. This calculation includes the Canadian oil and gas business, with a competitive reserve life index of 9.7 years, and the U.S. oil and gas business, with a reserve life index of 25.4 years, and Provident's Midstream business, operating plants and facilities with lifespans of 30 or 40 years and modest maintenance capital requirements. Provident's reserve life index has increased in each of the last five years.

MIDSTREAM BUSINESS UNIT

Provident's natural gas liquids (NGL) business features high-quality, long-life physical assets and an excellent competitive position. The business extracts and separates NGL (ethane, propane, butane, condensate) from raw natural gas, and stores, transports and markets finished products across North America.

BUSINESS DRIVERS

- The natural gas feedstock for Provident's midstream business comes from producers throughout Alberta and B.C., limiting the risk of insufficient supply from any one area. Future long-term supply potential exists with arctic gas.
- Having large NGL storage capacity is an advantage in a seasonal business – Provident can produce and store product in the spring and summer months for sale in the fall and winter months, when demand and prices are typically higher.
- Provident's access to the Enbridge west-to-east pipeline system to ship NGL products, as well as a large fleet of proprietary rail cars, enables Provident to access premium markets for NGL products.

2007 RESULTS

- Midstream delivered EBITDA of over $225 million in 2007, for an outstanding return on investment.
- The new condensate rail rack at Redwater expanded Provident's capacity to provide condensate to heavy oil and oil sands producers, who use it as a diluent for transporting their products.
- The construction of two new 600,000-barrel underground storage caverns at Redwater proceeded on time and on budget.
- Sales volumes of 120,785 barrels per day (consistent with 2006 results).

BUSINESS OUTLOOK

- The rapid development of the Alberta oil sands offers growth opportunities to Provident, as a supplier of necessary products and services to oil sands producers.
- Provident's Redwater facility is strategically located in the industrial heartland of Alberta where a number of oil sands upgraders are being built.
- The Redwater facility's excellent land position gives the potential to add more underground storage caverns over time.
- The high efficiency of Provident's Empress facility positions it well for the future even in the event of declining natural gas exports from western Canada.

CANADIAN UPSTREAM BUSINESS UNIT

The Canadian upstream business unit produces oil and natural gas across seven core areas, primarily in Alberta and Southern Saskatchewan. Production is weighted 58 percent natural gas, and 42 percent crude oil and natural gas liquids. Provident's Canadian assets are stable, low-risk producing properties. Natural production declines are offset by internal drilling and optimization, and by acquisitions. The Canadian upstream team has succeeded in strengthening the asset mix considerably over time, and in optimizing the results from those assets.

BUSINESS DRIVERS

- The positive effect of rising crude oil prices in 2007 was offset by weak natural gas prices and a rising Canadian dollar.
- As 2011 approaches, the pending taxation of income trusts drove consolidations and structural changes in the industry in 2007.
- Operating costs rose across western Canada in 2007, due to the strong demand for services in the industry and costs that are sensitive to commodity prices (e.g. power).
- The Alberta government announced a new higher royalty regime to come into effect in 2009, causing concern in the industry. The impact on Provident is mitigated by its diverse portfolio of assets.

2007 RESULTS

- Average daily production rose in 2007 to 26,500 boed, driven by acquisitions and drilling success.
- The Capitol Energy and Triwest acquisitions contributed to the increase in the Canadian proved plus probable reserves by 37 percent; the Canadian reserve life index increased to 9.7 years.
- Finding, development and acquisition (FD&A) costs in 2007, including revisions and future development costs (FDC) were $23.31 per barrel.
- Per-barrel operating costs increased by four percent to $11.62, well below the industry-wide average increase.

BUSINESS OUTLOOK

- Provident now has a Canadian drilling inventory of potentially 1,000 identified drilling and recompletion opportunities, providing a solid internal opportunity suite.
- Production from Dixonville and Southeast Saskatchewan is expected to grow in 2008, as drilling programs continue.
- Provident expects drilling and operating costs to ease somewhat in 2008, as activity in the sector levels off.
- The volatile markets of 2007 have created acquisition opportunity in the sector. Provident will continue to be highly selective in evaluating potential acquisitions, seeking only high quality, long-life assets with growth potential.

U.S. UPSTREAM BUSINESS UNIT

Provident's U.S. business unit produces oil and natural gas from California, Wyoming, Michigan, Indiana, Kentucky, Florida and Texas. The business unit consists of two operating entities. BreitBurn Energy Partners, L.P. is a publicly-traded master limited partnership (MLP) trading on the NASDAQ (trading symbol: BBEP) of which Provident owns approximately 22 percent and owns 96 percent of the General Partner. BreitBurn Energy Company L.P. (BreitBurn) is a 96 percent-owned, privately-held subsidiary. Provident consolidates all production, financial and reserves results from both entities.

BUSINESS DRIVERS

- Market support for the MLP strategy has provided a competitive cost of capital enabling BreitBurn to grow quickly through accretive acquisitions.
- BreitBurn's high-quality asset base is characterized by stable, long-life production.
- The U.S. business unit operates in regions with mature assets and consolidation opportunities to increase production through acquisition.
- The acquisition of large gas-producing assets from Quicksilver late in 2007 balanced BreitBurn's production profile between oil and natural gas.

2007 RESULTS

- Average U.S. production of 12,100 boed was up 57 percent from 2006 production.
- Four accretive acquisitions of high-quality assets increased the U.S. oil and gas production to approximately 24,000 boed by the end of the year.
- The Orcutt project in California began steaming late in 2007. Orcutt is a high-potential thermal oil project owned by BreitBurn.
- While operating costs are higher than they are in Canada, field operating netbacks remain strong at $34.46 per barrel.

BUSINESS OUTLOOK

- The assets acquired from Quicksilver late in 2007 provide attractive growth potential for the MLP.
- The MLP has the financial flexibility to continue to pursue accretive acquisitions and consolidation opportunities.
- The Orcutt thermal oil project offers growth potential for many years to come.
- Provident has announced its intention to monetize these U.S. assets to capture their value for unitholders in conjunction with the overall strategic review of its business.

CORPORATE GOVERNANCE

The primary responsibility of Provident's Board of Directors is to provide effective stewardship over Provident's affairs for the benefit of unitholders, investors, employees and other stakeholders.

Since the inception of the Trust in March 2001, the Board has developed and implemented corporate governance practices to ensure it has the authority, expertise, systems and processes to review and evaluate Provident's strategic direction, financial performance, operations and executive performance, and to make decisions independent of management.

BOARD OF DIRECTORS

- Provident has ten directors, nine of whom are non-management and eight of whom are independent. The Chairman of the Board is an independent director, separate from the role of President and CEO.
- The Board has three standing committees: the Audit Committee; the Governance, Human Resources and Compensation Committee; and the Reserves, Operations and EH&S Committee. Each committee meets quarterly and more frequently as required.
- All members of the Audit Committee and the Governance, Human Resources and Compensation Committee are independent directors.
- The Board meets in person at least six times per year or as frequently as necessary. In 2007 the full Board met 11 times.

GOVERNANCE SYSTEMS

- Provident's Board of Directors and officers closely monitor governance and financial disclosure reforms and implement changes to Provident's governance policies and practices as necessary to ensure compliance with the Sarbanes-Oxley Act of 2002 (SOX), relevant new rules issued by the U.S. Securities Commission, the New York Stock Exchange, The Toronto Stock Exchange, other applicable regulatory authorities and industry best practices.
- In 2007, Provident won the "Best in Class" award for Financial Statements and Analysis within the Infrastructure Trust Fund category at the Oilweek Annual Report Awards.
- Provident has a strong Board of Directors and management team, with diverse backgrounds and expertise spanning business leadership, geology, finance, accounting, upstream and midstream operations, law and government.
- All employees are required to review and sign the Code of Business Conduct annually.

RISK MANAGEMENT

- Provident has an Enterprise Risk Management program that is designed to identify and manage risks that could negatively impact the business, operations or results.
- Provident uses a disciplined hedging program that protects a portion of the Trust's cash flow and supports continued unitholder distributions, capital programs and bank financing.
- Provident has an insurance program in place to mitigate the economic costs associated with risks to the business, its assets and its people.
- Provident manages counterparty exposure with a credit policy that establishes limits by counterparty based upon an analysis of financial information and other business factors.

CORPORATE RESPONSIBILITY

Provident takes a disciplined and responsible approach to environmental protection, health and safety, and community relations.

Provident's philosophy and attitude toward all business and stakeholder relationships is captured in its RICE values – respect, integrity, creativity and excellence. Provident also has formal policies on environment, health and safety, and community investment.

ENVIRONMENT

- Provident is a platinum-level participant in the Stewardship program, a program of benchmarking, auditing and best practices around corporate responsibility that is administered by the Canadian Association of Petroleum Producers.
- Provident operates in ecologically sensitive areas, such as the natural grasslands of Southwest Saskatchewan that are the habitat of the endangered swift fox. Field operators work closely with environmental consultants and government officials to ensure habitat protection.
- Provident has had a greenhouse gas management program in place since 2003, focused on reducing the greenhouse gas intensity of oil and gas production.
- The Trust has a formal environmental management system.

HEALTH & SAFETY

- In 2006, Provident received a Certificate of Recognition (COR) from Alberta Employment, Immigration and Industry, which recognized the Trust's strong safety culture. The 2007 maintenance audit reconfirmed Provident's COR status, with a higher score than the original audit.
- The Trust's emergency response system is well established and regularly tested to ensure a rapid and comprehensive response to any operational incidents.
- Provident's positive work environment is demonstrated by staff turnover rates below the industry average. Health and fitness subsidies for employees promote a culture of wellness and work-life balance.

COMMUNITY INVESTMENT PROGRAM

Our Community Investment Program encourages the investment of human and financial resources in the communities in which we live and work and focuses our resources primarily in the support of youth in the following core areas:

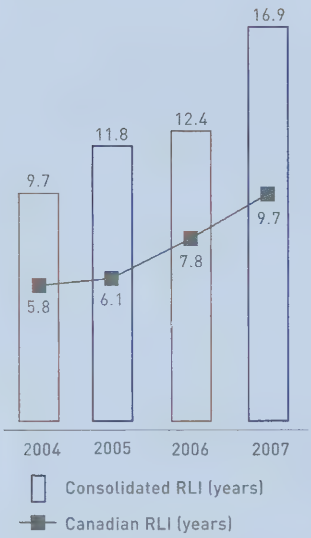
> *Education:* programs that develop academic skills, self respect, self reliance and personal responsibility and entrepreneurship;
>
> *Health & Wellness:* programs that promote physical and mental health, rehabilitation and the treatment of disease; and
>
> *Community Development:* programs that positively affect the long-term quality of life in a community.

In addition to monetary donations, Provident embraces and supports other investment initiatives including:

- In-kind donations; and
- Employee programs.

RESERVES INFORMATION

RESERVE LIFE INDEX



STRENGTHENING ASSETS

A combination of drilling and acquisitions increased Provident's reserve base in 2007.

Canadian Upstream RLI increased 24 percent to **9.7 years**

Consolidated Upstream RLI increased 36 percent to **16.9 years**

Provident also calculates a total "Economic Life Index" for the Trust, which takes into account the long-life Midstream assets.

The year-end 2007 Economic Life Index increased to **18.5 years**

CONSOLIDATED RESERVES SUMMARY [a] [b]

Using McDaniel January 1, 2008 Price Forecast

	GROSS RESERVES[c]						NET RESERVES[d]					
	Light Medium Crude Oil (Mbbl)	Heavy Crude Oil (Mbbl)	Total Oil (Mbbl)	NGL (Mbbl)	Natural Gas (MMcf)	Total Boe (Mboe)	Light Medium Crude Oil (Mbbl)	Heavy Crude Oil (Mbbl)	Total Oil (Mbbl)	NGL (Mbbl)	Natural Gas (MMcf)	Total Boe (Mboe)
Proved reserves												
Producing	73,638	10,882	84,520	4,774	699,075	205,807	64,520	9,819	74,339	3,854	579,689	174,808
Non-producing	4,247	1,547	5,794	432	60,065	16,236	3,737	1,513	5,250	351	47,443	13,508
Undeveloped	13,117	3,003	16,120	930	83,291	30,932	11,138	2,867	14,005	775	69,030	26,285
Total proved	91,002	15,432	106,434	6,136	842,431	252,975	79,395	14,199	93,594	4,981	696,162	214,601
Probable	31,583	9,189	40,772	1,721	161,639	69,433	26,332	8,760	35,092	1,353	135,036	58,951
TOTAL proved plus probable	122,585	24,621	147,206	7,857	1,004,069	322,408	105,727	22,959	128,686	6,333	831,198	273,552

(a) Tables may not add due to rounding.

(b) U.S. Reserves are reported based on 100% of the interests of BreitBurn Energy Company L.P. (BreitBurn) and of BreitBurn Energy Partners L.P. (MLP) in the U.S. properties. As of December 31, 2007 Provident indirectly held approximately 96% of the outstanding partnership interests of BreitBurn with the remaining approximately 4% of the partnership interests held by BreitBurn's co-founders and co-chief executive officers. As of December 31, 2007 Provident indirectly held approximately 22% of the outstanding partnership interests of the MLP with the remaining approximately 78% of the partnership interests held by public unitholders and BreitBurn's co-founders and co-chief executive officers. This is consistent with Provident's financial reporting.

(c) Gross Reserves are Provident's working interest (operated or non-operated) share before deduction of royalties and without including any royalty interests of Provident.

(d) Net Reserves are Provident's working interest (operated or non-operated) share after deduction of royalty obligations, plus Provident's royalty interests in reserves.

RESERVES INFORMATION

Oil and Natural Gas Reserves

Provident's Canadian reserves were evaluated by McDaniel & Associates Consultants Ltd. (McDaniel) and by AJM Petroleum Consultants (AJM) effective December 31, 2007 in accordance with the Canadian Securities Administrators' National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities (NI 51-101).

Provident's United States reserves were evaluated by Netherland, Sewell & Associates, Inc. (NSAI) and by Schlumberger Data and Consulting Services (DCS) effective December 31, 2007 in accordance with NI 51-101. The Canadian and U.S evaluations used the McDaniel price forecast. McDaniel, AJM, NSAI and DCS are independent qualified reserves evaluators appointed pursuant to NI 51-101. Additional information pertaining to NI 51-101 and some of the key reserves definitions are provided at the conclusion of the Reserves section. Additional details on the Trust's reserves can be found in Form NI 51-101 F1.

To provide clarity, reserves and values are provided by country and on a consolidated basis. For consistency with Provident's financial reporting U.S. reserves are reported based on 100 percent of the interests of BreitBurn Energy Company L.P. (BreitBurn) and of BreitBurn Energy Partners L.P. (the "MLP") in the U.S. properties. As of December 31, 2007 Provident indirectly held approximately 96 percent of the outstanding partnership interests of BreitBurn with the remaining approximately four percent of the partnership interests held by BreitBurn's co-founders and co-chief executive officers. As of December 31, 2007 Provident indirectly held approximately 22 percent of the outstanding partnership interests of the MLP with the remaining approximately 78 percent of the partnership interests held by public unitholders and BreitBurn's co-founders and co-chief executive officers.

Provident Consolidated Oil and Natural Gas Reserves

Provident had a very successful year with respect to acquisitions and reserve additions in the drive to continually support the sustainability of the Trust. Acquisitions in Canada and in the U.S. improved the quality of the Trust's asset base, as evidenced by the increased reserve life index (RLI). Internal development activities in Western Canada, California and Wyoming were successful in replacing 57 percent of total production. The Trust's reserves increased after production with company interest proved producing reserves growing from 89,851 thousand barrels of oil equivalent[1] (Mboe) to 206,063 Mboe, total proved growing from 117,806 Mboe to 253,272 Mboe, and proved plus probable growing from 153,021 Mboe to 322,826 Mboe.

Consolidated Oil and Natural Gas Reserves and Present Values

Provident's Consolidated oil and natural gas reserves and present value of estimated future cash flows based on forecast prices and costs using the McDaniel price forecast are summarized in the following tables. Reserves are presented on a Gross (working interest) and Net basis (refer to the notes under the tables and to the Definitions at the end of the Reserves section for explanations of company share, working interest, gross and net).

[1] A barrel of oil equivalent (BOE) is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent value equivalency at the wellhead. BOE's may be misleading, particularly if used in isolation. Conversion ratios of 6 Mcf: 1 bbl were used for natural gas and 1:1 for heavy oil and natural gas liquids.

Provident Consolidated Reserves Summary[a][b]

Using McDaniel Price Forecast

	Gross Reserves[c]						Net Reserves[d]					
	Light & Medium Crude Oil (Mbbl)	Heavy Crude Oil (Mbbl)	Total Oil (Mbbl)	NGL (Mbbl)	Natural Gas (MMcf)	Total Boe (Mboe)	Light & Medium Crude Oil (Mbbl)	Heavy Crude Oil (Mbbl)	Total Oil (Mbbl)	NGL (Mbbl)	Natural Gas (MMcf)	Total Boe (Mboe)
Proved Reserves												
Producing	73,638	10,882	84,520	4,774	699,075	205,807	64,520	9,819	74,339	3,854	579,689	174,808
Non-Producing	4,247	1,547	5,794	432	60,065	16,236	3,737	1,513	5,250	351	47,443	13,508
Undeveloped	13,117	3,003	16,120	930	83,291	30,932	11,138	2,867	14,005	775	69,030	26,285
Total Proved	91,002	15,432	106,434	6,136	842,431	252,975	79,395	14,199	93,594	4,981	696,162	214,601
Probable	31,583	9,189	40,772	1,721	161,639	69,433	26,332	8,760	35,092	1,353	135,036	58,951
TOTAL Proved plus Probable	122,585	24,621	147,206	7,857	1,004,069	322,408	105,727	22,959	128,686	6,333	831,198	273,552

(a) Tables may not add due to rounding.

(b) U.S. Reserves are reported based on 100% of the interests of BreitBurn Energy Company L.P. (BreitBurn) and of BreitBurn Energy Partners L.P. (the "MLP") in the U.S. properties. As of December 31, 2007 Provident indirectly held approximately 96% of the outstanding partnership interests of BreitBurn with the remaining approximately 4% of the partnership interests held by BreitBurn's co-founders and co-chief executive officers. As of December 31, 2007 Provident indirectly held approximately 22% of the outstanding partnership interests of the MLP with the remaining approximately 78% of the partnership interests held by public unitholders and BreitBurn's co-founders and co-chief executive officers. This is consistent with Provident's financial reporting.

(c) Gross Reserves are Provident's working interest (operated or non-operated) share before deduction of royalties and without including any royalty interests of Provident.

(d) Net Reserves are Provident's working interest (operated or non-operated) share after deduction of royalty obligations, plus Provident's royalty interests in reserves.

Present Value of Consolidated Reserves

	Present Value ($000's) Before Tax Discounted at				
	0%	8%	10%	15%	20%
Proved Reserves					
Producing	$ 6,251,207	$ 3,128,956	$ 2,818,145	$ 2,292,954	$ 1,961,080
Non-Producing	$ 533,094	$ 275,968	$ 244,000	$ 187,078	$ 149,900
Undeveloped	$ 881,581	$ 420,408	$ 364,282	$ 263,844	$ 197,582
Total Proved	$ 7,665,882	$ 3,825,332	$ 3,426,427	$ 2,743,876	$ 2,308,562
Probable	$ 2,386,511	$ 983,831	$ 835,162	$ 587,853	$ 438,516
TOTAL Proved plus Probable	$ 10,052,393	$ 4,809,163	$ 4,261,590	$ 3,331,729	$ 2,747,078

	Present Value ($000's) After Tax[a] Discounted at				
	0%	8%	10%	15%	20%
Proved Reserves					
Producing	$ 6,114,740	$ 3,093,166	$ 2,789,489	$ 2,274,097	$ 1,946,690
Non-Producing	541,352	278,757	246,268	188,536	150,930
Undeveloped	817,687	398,130	346,030	252,076	189,539
Total Proved	7,473,779	3,770,053	3,381,787	2,714,709	2,287,158
Probable	2,146,124	925,739	792,717	568,019	429,476
TOTAL Proved plus Probable	$ 9,619,903	$ 4,695,792	$ 4,174,504	$ 3,282,728	$ 2,716,634

(a) After tax values include U.S. State and Federal Taxes as well as with holding tax on funds that flow back to Provident Energy Ltd. In Canada plus Canadian Federal and Provincial taxes beginning January 1, 2011.

COGP Oil and Natural Gas Reserves

McDaniel evaluated all of Provident's Canadian oil and natural gas reserves, except the Rainbow area assets of northwest Alberta which were evaluated by AJM. Drilling activity made a significant contribution with total proved plus probable drilling and recompletion additions replacing 44 percent of Canadian production. The acquisitions of Capitol Energy Resources Ltd. (Capitol) and Triwest Energy Inc. (Triwest) plus various smaller acquisitions added proved plus probable reserves of 33,292 Mboe. To comply with NI 51-101 requirements that acquisitions be reported as evaluated at the time of the year-end filing the 2007 acquisitions are reported herein as per the McDaniel December 31, 2007 evaluation with actual production added back to develop the actual volumes acquired at the time of acquisition.

Over 90 percent of the value of the assets acquired from Capitol is associated with the Dixonville Montney "C" pool in northwest Alberta. This well-delineated homogeneous pool, which produces 30 degree API oil, is being developed using horizontal wells and waterflood technology. All of the production is 100 percent working interest and is operated by Provident. The assets acquired from Triwest are located principally in the Steelman, Crystal Hills and Ingoldsby areas in southeast Saskatchewan. These properties, which produce light crude oil, are also developed using horizontal well technology.

Revisions, excluding economic factors, accounted for a five percent increase in proved developed producing (PDP) reserves and a two percent increase in total proved reserves. The positive revisions are an indication of the high degree of confidence in Provident's Canadian reserves. Provident's percentage of PDP reserves has decreased from 62 percent to 51 percent of total proved plus probable reserves since December 2006 due to the acquisition of undeveloped reserves from Capitol, primarily at Dixonville, Alberta and from Triwest in southeast Saskatchewan. Changes in commodity prices had no significant impact on Canadian reserve volumes. After accounting for production of 9,676 Mboe, acquisitions, divestitures, additions and revisions resulted in a 37 percent increase in company share proved plus probable reserves from 74,137 Mboe on December 31, 2006 to 101,239 Mboe (100,820 Mboe WI share) at December 31, 2007.

COGP oil and natural gas reserves and present value of estimated future cash flows based on forecast prices and costs are summarized in the following tables. The impact of Federal income tax changes that were enacted during 2007 have been incorporated in the tables showing After Tax values. According to the new tax laws the Trust is expected to be taxable beginning January 1, 2011. Tax pools held by the Trust on its Canadian assets will defer the impact of these changes such that only the value of proved plus probable reserves will be affected.

In October 2007, the Alberta government announced its intention to increase crown royalties effective January 1, 2009. As of December 31, 2007, legislation enabling the Alberta new royalty framework had not been passed. Furthermore, the government had not provided sufficient clarity on a number of issues to allow precise calculation of net reserves and net present value under the new proposed royalties. Therefore, COGP reserves as presented herein are based on the existing royalty regime. High and low sensitivities, which were run to determine the potential impact of the proposed new royalty framework, indicate no impact on company interest reserves but a potential eight to ten percent decrease in before tax net present value (discounted at 10%) of COGP proved plus probable reserves. Details of reserves and values for these sensitivities are provided in Form NI 51-101 F1.

COGP Reserves Summary[a]

Using McDaniel Price Forecast

	Gross Reserves[b]						Net Reserves[c]					
	Light & Medium Crude Oil	Heavy Crude Oil	Total Oil	NGL	Natural Gas	Total Boe	Light & Medium Crude Oil	Heavy Crude Oil	Total Oil	NGL	Natural Gas	Total Boe
	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(MMcf)	(Mboe)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(MMcf)	(Mboe)
Proved Reserves												
Producing	19,015	1,142	20,157	2,222	172,128	51,067	16,167	966	17,133	1,646	145,207	42,980
Non-Producing	895	273	1,168	48	15,613	3,818	781	239	1,020	38	12,020	3,061
Undeveloped	5,520	423	5,943	114	21,791	9,689	4,750	361	5,111	75	17,990	8,184
Total Proved	25,429	1,838	27,267	2,384	209,532	64,573	21,697	1,566	23,264	1,759	175,216	54,225
Probable	19,932	1,885	21,817	880	81,299	36,247	16,506	1,641	18,147	646	69,163	30,321
TOTAL Proved plus Probable	45,361	3,723	49,084	3,264	290,832	100,820	38,204	3,207	41,411	2,405	244,379	84,545

(a) Tables may not add due to rounding

(b) Gross Reserves are Provident's working interest (operated or non-operated) share before deduction of royalties and without including any royalty interests of Provident.

(c) Net Reserves are Provident's working interest (operated or non-operated) share after deduction of royalty obligations, plus Provident's royalty interests in reserves.

Present Value of COGP Reserves [a][b]

	Present Value ($000's) Before Tax Discounted at				
	0%	8%	10%	15%	20%
Proved Reserves					
Producing	$ 1,367,465	$ 1,032,120	$ 975,009	$ 860,619	$ 774,765
Non-Producing	73,575	62,671	57,748	47,762	40,610
Undeveloped	214,065	118,607	103,567	74,491	53,742
Total Proved	1,655,105	1,213,398	1,136,324	982,872	869,117
Probable	1,258,344	511,244	437,219	315,866	243,146
TOTAL Proved plus Probable	$ 2,913,449	$ 1,724,642	$ 1,573,543	$ 1,298,738	$ 1,112,263

	Present Value ($000's) After Tax[b] Discounted at				
	0%	8%	10%	15%	20%
Proved Reserves					
Producing	$ 1,367,465	$ 1,032,120	$ 975,009	$ 860,619	$ 774,765
Non-Producing	73,575	62,671	57,748	47,762	40,610
Undeveloped	214,065	118,607	103,567	74,491	53,742
Total Proved	1,655,105	1,213,398	1,136,324	982,872	869,117
Probable	1,061,182	457,888	396,459	293,738	230,313
TOTAL Proved plus Probable	$ 2,716,287	$ 1,671,286	$ 1,532,783	$ 1,276,610	$ 1,099,430

(a) Tables may not add due to rounding

(b) After tax values include the impact of Canadian Federal and Provincial Income taxes beginning January 1, 2011.

USOGP Oil and Natural Gas Reserves

Provident's U. S. oil and natural gas reserves were evaluated by Netherland, Sewell and Associates, Inc. (NSAI) and by Schlumberger Data and Consulting Services (DCS) effective December 31, 2007 in accordance with NI 51-101. Michigan, Indiana and Kentucky properties that were acquired by BreitBurn Energy Partners L.P. were evaluated by DCS while the remaining properties were evaluated by NSAI. The U.S evaluations used the McDaniel price forecast. NSAI and DCS are qualified reserve evaluators in accordance with NI 51-101.

Provident's USOGP division had a very successful year with respect to acquisitions. BreitBurn closed four major and two small acquisitions during the year thereby increasing proved plus probable reserves by 148,858 Mboe. The most significant was the acquisition of Michigan, Indiana and Kentucky assets with over 5,000 gross wells which produce gas from the Antrim and New Albany shales and oil and gas from conventional reservoirs. BreitBurn acquired oil producing assets in the Sunniland Trend in southern Florida and oil and gas producing assets in the Texas Permian Basin. BreitBurn also increased its working interests in the Sawtelle and East Coyote fields in California and several other oil fields in California and Wyoming.

Drilling activity in California and Wyoming added proved plus probable reserves of 3,731 Mboe, replacing 84 percent of U.S. production. These additions include reserves added as a result of continuing heavy oil development at the Orcutt Hill field in the Santa Maria Basin of California where steam injection and production have commenced. The North Sunshine field in Wyoming was discovered in 1928 but BreitBurn set a new production record in May 2007.

Technical revisions accounted for a seven percent decrease in proved plus probable reserves. These revisions are primarily associated with undeveloped drilling and waterflood reserves in the Los Angeles basin. After accounting for production of 4,425 Mboe and these revisions, acquisitions and additions resulted in the significant growth of company share proved plus probable reserves from 78,885 Mboe as of December 31, 2006 to 221,589 Mboe as of December 31, 2007.

USOGP oil and natural gas reserves and present value of estimated future cash flows based on forecast prices and costs are summarized in the following tables.

USOGP Reserves Summary[a][b]

Using McDaniel Price Forecast

	Gross Reserves						Net Reserves					
	Light & Medium Crude Oil (Mbbl)	Heavy Crude Oil (Mbbl)	Total Oil (Mbbl)	NGL (Mbbl)	Natural Gas (MMcf)	Total Boe (Mboe)	Light & Medium Crude Oil (Mbbl)	Heavy Crude Oil (Mbbl)	Total Oil (Mbbl)	NGL (Mbbl)	Natural Gas (MMcf)	Total Boe (Mboe)
Proved Reserves												
Producing	54,624	9,740	64,364	2,552	526,947	154,741	48,353	8,853	57,207	2,209	434,482	131,829
Non-Producing	3,352	1,274	4,626	384	44,451	12,419	2,956	1,274	4,230	314	35,423	10,447
Undeveloped	7,597	2,580	10,178	816	61,500	21,243	6,388	2,505	8,894	700	51,041	18,100
Total Proved	65,573	13,594	79,167	3,753	632,898	188,402	57,698	12,632	70,330	3,222	520,946	160,376
Probable	11,651	7,304	18,955	841	80,340	33,186	9,826	7,119	16,945	707	65,873	28,630
TOTAL Proved plus Probable	77,224	20,898	98,122	4,593	713,238	221,589	67,523	19,752	87,275	3,929	586,819	189,007

(a) Tables may not add due to rounding.

(b) U.S. Reserves are reported based on 100% of the interests of BreitBurn Energy Company L.P. (BreitBurn) and of BreitBurn Energy Partners L.P. (the "MLP") in the U.S. properties. As of December 31, 2007 Provident indirectly held approximately 96% of the outstanding partnership interests of BreitBurn with the remaining approximately 4% of the partnership interests held by BreitBurn's co-founders and co-chief executive officers. As of December 31, 2007 Provident indirectly held approximately 22% of the outstanding partnership interests of the MLP with the remaining approximately 78% of the partnership interests held by public unitholders and BreitBurn's co-founders and co-chief executive officers. This is consistent with Provident's financial reporting.

Present Value of USOGP Reserves [a][b]

	Present Value ($000's) Before Tax Discounted at				
	0%	8%	10%	15%	20%
Proved Reserves					
Producing	$ 4,883,742	$ 2,096,836	$ 1,843,136	$ 1,432,335	$ 1,186,315
Non-Producing	459,519	213,297	186,251	139,316	109,290
Undeveloped	667,516	301,801	260,716	189,353	143,840
Total Proved	6,010,777	2,611,934	2,290,103	1,761,004	1,439,445
Probable	1,128,167	472,587	397,944	271,987	195,370
TOTAL Proved plus Probable	$ 7,138,944	$ 3,084,521	$ 2,688,047	$ 2,032,991	$ 1,634,815

	Present Value ($000's) After Tax[c] Discounted at				
	0%	8%	10%	15%	20%
Proved Reserves					
Producing	$ 4,747,275	$ 2,061,046	$ 1,814,480	$ 1,413,479	$ 1,171,925
Non-Producing	467,777	216,086	188,519	140,774	110,320
Undeveloped	603,622	279,523	242,464	177,585	135,797
Total Proved	5,818,674	2,556,655	2,245,463	1,731,837	1,418,041
Probable	1,084,942	467,851	396,258	274,281	199,163
TOTAL Proved plus Probable	$ 6,903,616	$ 3,024,506	$ 2,641,720	$ 2,006,118	$ 1,617,204

(a) Tables may not add due to rounding
(b) Values in Canadian dollars
(c) After tax values include U.S. State and Federal Taxes as well as with holding tax on funds that flow back to Provident Energy Ltd. in Canada.

USOGP Proportionate Information

For consistency with Provident's financial reporting U.S. reserves are reported based on 100 percent of the interests of BreitBurn Energy Company L.P. (BreitBurn) and of BreitBurn Energy Partners L.P. (the "MLP") in the U.S. properties. As of December 31, 2007 Provident held approximately 96% of BreitBurn and approximately 22% of the MLP. The following tables provide the proportionate information on the reserves and value of USOGP.

USOGP Reserves and Value Proportionate Information[a][b]

Using McDaniel Price Forecast

	Gross Reserves					Present Value ($000's) Before Tax Discounted at				
MLP	Light & Medium Oil	Heavy Oil	NGL	Natural Gas	Total Boe					
Proved	(Mbbl)	(Mbbl)	(Mbbl)	(MMcf)	(Mboe)	0%	8%	10%	15%	20%
Producing	40,057	7,608	2,522	523,327	137,408	4,454,324	1,872,302	1,643,794	1,276,330	1,057,417
Non-Producing	3,094	0	384	44,451	10,887	414,479	183,010	158,378	116,154	89,520
Undeveloped	5,430	646	734	58,289	16,525	559,411	242,041	208,209	150,382	114,045
Total Proved	48,581	8,254	3,641	626,068	164,820	5,428,215	2,297,354	2,010,380	1,542,866	1,260,982
Probable	4,150	1,631	532	70,400	18,046	637,428	256,203	216,914	151,440	111,688
TOTAL Proved plus Probable	52,731	9,884	4,173	696,468	182,866	6,065,643	2,553,556	2,227,294	1,694,306	1,372,670
Provident's Interest of MLP(a)										
Proved										
Producing	8,812	1,674	555	115,132	30,230	979,951	411,906	361,635	280,793	232,632
Non-Producing	681	0	85	9,779	2,395	91,185	40,262	34,843	25,554	19,694
Undeveloped	1,195	142	162	12,824	3,635	123,071	53,249	45,806	33,084	25,090
Total Proved	10,688	1,816	801	137,735	36,260	1,194,207	505,418	442,284	339,430	277,416
Probable	913	359	117	15,488	3,970	140,234	56,365	47,721	33,317	24,571
TOTAL Proved plus Probable	11,601	2,175	918	153,223	40,231	1,334,441	561,782	490,005	372,747	301,987
BreitBurn										
Proved										
Producing	14,567	2,132	30	3,620	17,332	429,418	224,534	199,343	156,005	128,899
Non-Producing	258	1,274	0	0	1,532	45,040	30,287	27,874	23,162	19,770
Undeveloped	2,167	1,935	82	3,211	4,718	108,104	59,760	52,507	38,971	29,795
Total Proved	16,992	5,341	112	6,831	23,583	582,562	314,580	279,723	218,138	178,463
Probable	7,501	5,674	309	9,940	15,140	490,739	216,385	181,030	120,547	83,682
TOTAL Proved plus Probable	24,493	11,014	421	16,770	38,722	1,073,302	530,965	460,754	338,685	262,145
Provident's Interest of BreitBurn(b)										
Proved										
Producing	13,984	2,047	29	3,475	16,639	412,241	215,553	191,369	149,765	123,743
Non-Producing	248	1,223	0	0	1,471	43,238	29,075	26,759	22,236	18,979
Undeveloped	2,080	1,857	78	3,082	4,530	103,780	57,369	50,407	37,412	28,603
Total Proved	16,312	5,127	107	6,557	22,639	559,260	301,997	268,534	209,412	171,325
Probable	7,201	5,447	297	9,542	14,534	471,110	207,729	173,789	115,725	80,334
TOTAL Proved plus Probable	23,513	10,574	404	16,099	37,173	1,030,369	509,726	442,323	325,138	251,659

Provident's Interest of USOGP

Proved	Gross Reserves: Light & Medium Oil (Mbbl)	Heavy Oil (Mbbl)	NGL (Mbbl)	Natural Gas (MMcf)	Total Boe (Mboe)	Present Value ($000's) Before Tax Discounted at: 0%	8%	10%	15%	20%
Producing	22,797	3,721	584	118,607	46,869	1,392,193	627,459	553,004	430,557	356,374
Non-Producing	929	1,223	85	9,779	3,866	134,424	69,338	61,602	47,790	38,674
Undeveloped	3,275	1,999	240	15,906	8,165	226,850	110,618	96,213	70,496	53,693
Total Proved	27,000	6,943	908	144,292	58,900	1,753,467	807,415	710,818	548,843	448,741
Probable	8,114	5,805	414	25,030	18,504	611,344	264,094	221,510	149,042	104,906
TOTAL Proved plus Probable	35,114	12,748	1,322	169,322	77,404	2,364,811	1,071,509	932,328	697,885	553,647

(a) Provident interest in MLP = 22%
(b) Provident interest in BreitBurn = 96%

Consolidated Proportionate Information

Provident's interest share of total United States and Canada reserves and value as of December 31, 2007 is shown in the following table.

United States and Canada Reserves and Value

Provident Interest using McDaniel Price Forecast

Proved	Gross Reserves: Light & Medium Oil (Mbbl)	Heavy Oil (Mbbl)	NGL (Mbbl)	Natural Gas (MMcf)	Total Boe (Mboe)	Present Value ($000's) Before Tax Discounted at: 0%	8%	10%	15%	20%
Producing	41,812	4,862	2,806	290,735	97,936	2,759,658	1,659,579	1,528,013	1,291,176	1,131,139
Non-Producing	1,823	1,496	132	25,392	7,683	207,998	132,009	119,350	95,552	79,283
Undeveloped	8,795	2,422	354	37,697	17,854	440,915	229,225	199,779	144,987	107,435
Total Proved	52,429	8,781	3,292	353,825	123,472	3,408,571	2,020,813	1,847,142	1,531,715	1,317,857
Probable	28,046	7,690	1,294	106,329	54,751	1,869,688	775,338	658,729	464,908	348,052
TOTAL Proved plus Probable	80,475	16,471	4,585	460,154	178,224	5,278,260	2,796,151	2,505,871	1,996,623	1,665,909

Provident Consolidated Reconciliation Summaries

The following reconciliation tables summarize Provident's consolidated reserve activity for each reserve category for the year ended December 31, 2007 on the basis of company share reserves. Working interest reserves as of December 31, 2007 are provided at the bottom of each table to tie back to the volumes provided in the previous tables.

Provident Consolidated Reconciliation Summary [d]
Proved Developed Producing

Company Share (WI +RI) [a][c]	Light & Medium Crude Oil Mbbl	Heavy Crude Oil Mbbl	Total Crude Oil Mbbl	Gas MMcf	NGL Mbbl	Total Mboe
Balance at December 31, 2006	49,133	6,738	55,871	188,738	2,524	89,851
Production	(6,068)	(996)	(7,064)	(39,110)	(518)	(14,101)
Drilling Activity						
Exploration Discoveries	132	0	132	0	0	132
Drilling Extensions	491	0	491	6,663	34	1,635
Recompletion	149	693	843	2,504	17	1,277
Transfer	1,808	0	1,808	4,113	15	2,509
Acquisition	26,510	3,802	30,311	533,180	2,573	121,748
Divestiture	(22)	0	(22)	(146)	(1)	(47)
Economic Factors	733	369	1,102	(1,439)	(0)	862
Technical Revisions	805	284	1,090	5,710	156	2,197
Balance at December 31, 2007	73,671	10,890	84,562	700,214	4,800	206,063
WI Share [b]						
Balance at December 31, 2007	73,638	10,882	84,520	699,075	4,774	205,807

Provident Consolidated Reconciliation Summary [d]
Total Proved

Company Share (WI +RI) [a][c]	Light & Medium Crude Oil Mbbl	Heavy Crude Oil Mbbl	Total Crude Oil Mbbl	Gas MMcf	NGL Mbbl	Total Mboe
Balance at December 31, 2006	63,076	11,958	75,034	236,464	3,362	117,806
Production	(6,068)	(996)	(7,064)	(39,110)	(518)	(14,101)
Drilling Activity						
Exploration Discoveries	132	0	132	0	0	132
Drilling Extensions	1,901	0	1,901	9,923	40	3,595
Recompletion	169	734	903	2,492	18	1,337
Transfer	981	0	981	1,900	6	1,303
Acquisition	36,547	3,802	40,349	641,842	3,692	151,015
Divestiture	(22)	0	(22)	(146)	(1)	(47)
Economic Factors	929	339	1,268	(1,318)	8	1,056
Technical Revisions	(6,611)	(396)	(7,007)	(8,270)	(440)	(8,825)
Balance at December 31, 2007	91,035	15,440	106,475	843,776	6,167	253,272
WI Share [b]						
Balance at December 31, 2007	91,002	15,432	106,434	842,431	6,136	252,975

Provident Consolidated Reconciliation Summary [d]
Total Proved plus Probable

Company Share (WI +RI) [a][c]	Light & Medium Crude Oil Mbbl	Heavy Crude Oil Mbbl	Total Crude Oil Mbbl	Gas MMcf	NGL Mbbl	Total Mboe
Balance at December 31, 2006	74,824	19,238	94,062	325,665	4,681	153,021
Production	(6,068)	(996)	(7,064)	(39,110)	(518)	(14,101)
Drilling Activity						
Exploration Discoveries	132	0	132	0	0	132
Drilling Extensions	3,778	0	3,778	14,531	56	6,256
Recompletion	209	887	1,096	3,125	23	1,640
Transfer	0	0	0	0	0	0
Acquisition	54,697	4,100	58,797	714,745	4,229	182,150
Divestiture	(28)	0	(28)	(261)	(1)	(73)
Economic Factors	283	383	666	(3,198)	2	135
Technical Revisions	(5,196)	1,020	(4,177)	(9,496)	(573)	(6,333)
Balance at December 31, 2007	122,630	24,632	147,262	1,006,000	7,898	322,826
WI Share [b]						
Balance at December 31, 2007	122,585	24,621	147,206	1,004,069	7,857	322,408

(a) Company share includes working interest (WI) and royalty interest (RI) volumes.

(b) WI share includes the Company's working interests only, and excludes volumes associated with royalties.

(c) Tables may not add due to rounding.

(d) U.S. Reserves are reported based on 100% of the interests of BreitBurn Energy Company L.P. (BreitBurn) and of BreitBurn Energy Partners L.P. (the "MLP") in the U.S. properties. As of December 31, 2007 Provident indirectly held approximately 96% of the outstanding partnership interests of BreitBurn with the remaining approximately 4% of the partnership interests held by BreitBurn's co-founders and co-chief executive officers. As of December 31, 2007 Provident indirectly held approximately 22% of the outstanding partnership interests of the MLP with the remaining approximately 78% of the partnership interests held by public unitholders and BreitBurn's co-founders and co-chief executive officers. This is consistent with Provident's financial reporting.

Price Forecast Summary

The following table summarizes the McDaniel January 1, 2008 price forecast used in evaluating Provident's reserves under forecast price and cost assumptions.

Year	Exchange Rate US$/Cdn$	WTI Crude at Cushing Oklahoma US$/bbl	Light, Sweet Crude at Edmonton Cdn$/bbl	Heavy Oil at Hardisty Cdn$/bbl	Alberta AECO Gas Spot Price Cdn$/MMbtu[a]
2008	1.000	90.00	89.00	55.30	6.80
2009	1.000	86.70	85.70	53.20	7.38
2010	1.000	83.20	82.20	50.50	7.38
2011	1.000	79.60	78.50	48.70	7.38
2012	1.000	78.50	77.40	48.00	7.49

(a) Alberta AECO Gas Spot price assuming 1,000 btu/scf

Reserve Life Index (RLI)

The acquisition of the Dixonville and southeast Saskatchewan assets increased the Trust's Reserve Life Index (RLI) in 2007. Provident's RLI of 16.9 years as of December 31, 2007 was determined by applying the average actual production rates for December 2007 to COGP and USOGP reserve volumes for each reserve category from the McDaniel, AJM, NSAI and DCS evaluations as of December 31, 2007

The following tables illustrate the reserve life index for Provident for the various product and reserve categories and the RLI by country as of December 31, 2007.

Provident Consolidated Reserve Life Index
Company share (WI + RI)

	December 31				
Total Crude Oil	2007	2006	2005	2004	2003
Proved Producing	9.8	9.7	8.2	6.5	3.0
Total Proved	12.4	13.1	11.7	8.9	3.9
Proved plus Probable	17.1	16.4	14.9	11.7	5.4
Natural Gas & NGL					
Proved Producing	11.6	5.2	4.5	4.2	4.4
Total Proved	14.0	6.5	6.0	5.5	4.9
Proved plus Probable	16.7	9.0	7.9	7.2	6.1
Oil Equivalent (6:1)					
Proved Producing	10.8	7.3	6.6	5.5	3.7
Total Proved	13.3	9.6	9.2	7.4	4.4
Proved plus Probable	16.9	12.4	11.8	9.7	5.7

Canada and United States Reserve Life Index
Company share (WI + RI)

	December 31, 2007	
Total Crude Oil	COGP	USOGP
Proved Producing	4.6	15.2
Total Proved	6.2	18.7
Proved plus Probable	11.2	23.2
Natural Gas & NGL		
Proved Producing	5.2	20.0
Total Proved	6.3	24.2
Proved plus Probable	8.7	27.3
Oil Equivalent (6:1)		
Proved Producing	4.9	17.7
Total Proved	6.2	21.6
Proved plus Probable	9.7	25.4

Finding, Development and Acquisition Costs

Finding and development costs (F&D) include all costs to develop reserves, including land and seismic costs. The methodology used to calculate F&D costs under NI 51-101 requires that F&D costs incorporate changes in future development capital (FDC) required to bring non-producing and undeveloped reserves to production. This capital, which is included in the reserves evaluations, is part of the ongoing development process necessary to bring production on stream and generate cash flow. Provident's FDC has increased over the past several years with the acquisition of undeveloped reserves. To provide clarity in the true costs to find and develop reserves, Provident does not include the FDC associated with acquisitions in the F&D costs. However, since FDC is a component of the cost of acquiring reserves Provident does include the FDC associated with acquisitions in the FD&A costs.

Drilling and recompletion activity during 2007 made a significant contribution with total proved additions of 5,064 Mboe and proved plus probable additions of 8,027 Mboe. As an energy trust and not an exploration oriented venture, Provident's focus is development and exploitation of reserves and promotes between reserve categories. As a result of capital expenditures during 2007, Provident promoted 2,509 Mboe of reserves into the proved developed producing category. The associated capital and any changes to it have been accounted for in the F&D calculations. Provident's all-in finding, development and acquisition costs for 2007 were $15.18/boe.

Acquisition costs include the cash cost of acquiring reserves and the fair value of liabilities assumed. NI 51-101 does not contemplate nor define acquisition costs. Provident has included goodwill on the corporate acquisitions as part of the purchase price allocation, and therefore forms part of the costs of acquiring the reserves.

The aggregate of the development costs incurred in the most recent financial year and the change during that year in estimated future development costs generally will not reflect total finding and development costs related to reserve additions for that year. A three-year average of F&D costs is a better reflection of full cycle economics and is therefore a more appropriate view of the cost of reserve additions. The three-year average FD&A cost does include the change in FDC, including acquisitions, over the three year period. Three-year average total proved and probable FD&A costs are $16.05 per boe, including reserve revisions and changes in FDC.

The following table presents the details of the 2007 Finding, Development and Acquisition cost calculation for Provident and illustrates the impact of including the change in future development capital in the calculation.

Provident Consolidated
2007 Finding, Development and Acquisition Costs (FD&A)

	Capital Expenditures ($000s)	Company Interest Reserve Additions[3] Mboe[4]	Reserves Costs $/boe[4]
Total Proved			
Total FD&A Costs[1] (a)	$ 2,498,730	149,566	$ 16.71
Change in FDC[2] (b)	185,856		
Total FD&A including change in FDC (a+b)	$ 2,684,587	149,566	$ 17.95
Proved + Probable			
Total FD&A Costs[1] (a)	$ 2,498,730	183,906	$ 13.59
Change in FDC[2] (b)	292,542		
Total FD&A including change in FDC (a+b)	$ 2,791,273	183,906	$ 15.18

Notes:

(1) Total FD&A Costs ($000s)

2007 Oil and Gas Capital Expenditures	$ 148,464
Property Acquisitions (net dispositions)	$ 1,754,023
Corporate Acquisitions	$ 596,243
Total Oil and Gas FD&A costs	$ 2,498,730

(2) Change in Future Development Costs ($000s)

	Total Proved	Proved plus Probable
FDC as of December 31, 2007	$ 335,387	$ 547,189
FDC as of December 31, 2006	$ 149,531	$ 254,647
Change in FDC	$ 185,856	$ 292,542

(3) Reserve Additions include revisions.

(4) BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 Mcf: 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. BOE conversions of 1:1 were used for Heavy Oil and NGL.

The following tables present finding and development costs and finding, development and acquisition costs for proved and proved plus probable reserves on a consolidated basis and by country.

Provident Consolidated Finding and Development Costs ($ per boe)

	2007	2006	2005	Three year average [d]
Finding and Development Costs per boe (includes FDC) [a][b][c]				
Proved				
Additions	$22.02	$26.84	$23.79	$23.88
Additions including revisions	- (e)	$13.68	$22.90	$30.76
Proved plus probable				
Additions	$19.82	$17.21	$16.37	$17.80
Additions including revisions	- (e)	$19.04	$28.39	$31.89
Finding, Development and Acquisition Costs per boe (includes FDC)				
Proved				
Proved excluding revisions	$17.06	$29.92	$12.03	$18.05
Proved including revisions	$17.95	$25.18	$11.88	$18.38
Proved plus probable				
Proved plus probable excluding revisions	$14.68	$21.56	$11.73	$15.35
Proved plus probable including revisions	$15.18	$22.04	$14.44	$16.05

(a) FDC - Future Development Capital

(b) Based on Company share reserves.

(c) BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 Mcf: 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

(d) Three year average is the average of 2005, 2006 and 2007. The aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development costs generally will not reflect total finding and development costs related to reserves additions for that year.

(e) Revisions exceed additions, therefore the calculation is not included in the table.

COGP Finding and Development Costs ($ per boe)

	2007	2006	2005	Three year average [d]
Finding and Development Costs per boe (includes FDC) [a][b][c]				
Proved				
Additions	$25.55	$24.76	$17.61	$22.20
Additions including revisions	$20.39	$25.06	$15.35	$19.36
Proved plus probable				
Additions	$20.23	$16.80	$11.61	$16.05
Additions including revisions	$24.42	$23.99	$15.01	$20.82
Finding, Development and Acquisition Costs per boe (includes FDC)				
Proved				
Proved excluding revisions	$41.48	$30.07	- (e)	$36.57
Proved including revisions	$39.76	$30.11	- (e)	$35.31
Proved plus probable				
Proved plus probable excluding revisions	$22.85	$22.12	- (e)	$23.36
Proved plus probable including revisions	$23.31	$23.04	- (e)	$24.48

(a) FDC - Future Development Capital

(b) Based on Company share reserves.

(c) BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 Mcf: 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

(d) Three-year average is the average of 2005, 2006 and 2007. The aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development costs generally will not reflect total finding and development costs related to reserves additions for that year.

(e) Calculation is not included in the table since dispositions exceed acquisitions plus additions.

USOGP Finding and Development Costs (Canadian $ per boe)

	2007	2006	2005	Three year average[d]
Finding and Development Costs per boe (includes FDC) [a][b][c]				
Proved				
Additions	$17.81	$29.46	- (e)	$26.48
Additions including revisions	- (e)	$9.24	- (e)	- (e)
Proved plus probable				
Additions	$19.35	$17.65	$22.32	$19.81
Additions including revisions	- (e)	$15.80	- (e)	- (e)
Finding, Development and Acquisition Costs per boe (includes FDC)				
Proved				
Proved excluding revisions	$13.45	$28.38	$10.57	$13.32
Proved including revisions	$14.35	$8.90	$10.80	$13.76
Proved plus probable				
Proved plus probable excluding revisions	$12.67	$17.08	$10.20	$12.47
Proved plus probable including revisions	$13.14	$15.29	$11.59	$13.03

(a) FDC - Future Development Capital, excluding USOGP Obligatory (Maintenance) capital.

(b) Based on Company share reserves.

(c) BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 Mcf: 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

(d) Three-year average is the average of 2005, 2006 and 2007. The aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development costs generally will not reflect total finding and development costs related to reserves additions for that year.

(e) Revisions exceed additions or dispositions exceed acquisitions plus additions, therefore the calculation is not included in the table.

National Instrument 51-101

Estimation and reporting of oil and natural gas reserves in Canada were governed by National Policy 2B (NP 2B) from the late 1970's until 2003. Effective September 2003 the Canadian Securities Administrators implemented new standards that govern all aspects of reserves disclosure in the form of National Instrument 51-101 (NI 51-101).

NI 51-101 requirements were updated effective December 28, 2007. NI 51-101 establishes prescribed disclosures regarding oil and natural gas information. NI 51-101 also enhanced corporate governance by mandating the involvement of independent reserves evaluators in the preparation of reserves data and assigning responsibility for the content of reserves data directly to management and the board of directors. Provident's reserves have been evaluated in accordance with the Canadian Oil and Gas Evaluation Handbook Volumes 1 and 2 ("COGEH") and comply with NI 51-101. Under NI 51-101, proved reserves are defined as having a high degree of certainty to be recoverable. Probable reserves are defined as those reserves that are less certain to be recovered than proved reserves. The targeted levels of certainty, in aggregate, are at least 90 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves and at least 50 percent probability that the quantities recovered will equal or exceed the sum of the estimated proved plus probable reserves. Under NI 51-101 standards proved plus probable are considered a "best estimate" of future recoverable reserves. The following outlines some of the key reserves definitions according to NI 51-101.

Reserve Definitions

Acquisitions and Dispositions: Positive or negative changes to the reserves as a result of purchasing or selling all or a portion of an interest in oil and gas properties.

Closing Balance: Reserves assigned at the end of the period.

Company Share: Includes working interest volumes before the deduction of royalties plus volumes equivalent to royalty interests received from others.

Drilling Extensions: Additions to reserves resulting from capital expenditures for step-out drilling in previously discovered reservoirs.

Economic Factors: Changes to reserves between the current and previous reporting periods resulting from different price forecasts, inflation rates, operating and capital cost escalation and regulatory changes.

Exploration Discoveries: Additions to reserves where no reserves were previously booked.

Improved Recovery: Additions to reserves resulting from capital expenditures associated with the installation of enhanced recovery schemes that were not previously included in the reserves category.

Infill Drilling: Additions to reserves resulting from capital expenditures for wells that were drilled in previously discovered reservoirs but were not drilled for enhanced recovery schemes. These additions were not previously included in the initial reserves assignment.

Net Reserves: Includes the company's share of gross reserves after the deduction of royalties plus volumes equivalent to royalty interests received from others and excludes volumes equivalent to royalties paid to others.

Opening Balance: Reserves assigned at the end of the last reporting period.

Production: Reductions in reserves due to production during the reporting period.

Technical Revisions: Positive or negative revisions to a reserves entity resulting from new technical data or revised interpretations on previously assigned reserves.

Working Interest: The Company's interest before royalties paid to or received from others.

MANAGEMENT'S DISCUSSION AND ANALYSIS

The following analysis provides a detailed explanation of Provident's operating results for the year ended December 31, 2007 compared to the year ended December 31, 2006 and should be read in conjunction with the consolidated financial statements of Provident. This analysis has been prepared using information available up to March 18, 2008.

Provident Energy Trust has diversified investments in certain segments of the energy value chain. Provident currently operates in three key business segments: Canadian crude oil and natural gas production ("COGP"), United States crude oil and natural gas production ("USOGP"), and Midstream. Provident's COGP business produces crude oil and natural gas from seven core areas in the western Canadian sedimentary basin. USOGP produces crude oil and natural gas in several states across the U.S.A. including California, Wyoming, Texas, Florida and Michigan. The Midstream business unit operates in Canada and the U.S.A. and extracts, processes, markets, transports and offers storage of natural gas liquids within the integrated facilities at Younger in British Columbia, Redwater and Empress in Alberta, Kerrobert in Saskatchewan, Sarnia in Ontario, Superior in Wisconsin and Lynchburg in Virginia.

This analysis commences with a summary of the consolidated financial and operating results followed by segmented reporting on the COGP business unit, the USOGP business unit and the Midstream business unit. The reporting focuses on the financial and operating measurements management uses in making business decisions and evaluating performance.

This analysis contains forward-looking information and statements. See "Forward-looking statements" at the end of the analysis for further discussion.

Consolidated funds flow from operations and cash distributions

Consolidated	Year ended December 31,		
($ 000s, except per unit data)	2007	2006	% Change
Revenue, Funds Flow from Operations and Distributions			
Revenue (net of royalties and financial derivative instruments)	$ 2,167,276	$ 2,187,253	(1)
Funds flow from operations	$ 468,255	$ 432,664	8
Per weighted average unit - basic and diluted [1]	$ 2.04	$ 2.20	(7)
Declared distributions	$ 333,352	$ 283,465	18
Per Unit	1.44	1.44	-
Percent of funds flow from operations distributed [2]	77%	67%	15

[1] Includes dilutive impact of unit options, exchangeable shares and convertible debentures.

[2] Calculated as declared distributions to unitholders divided by funds flow from operations less distributions to non-controlling interests of $35.8 million (2006 - $6.5 million).

Management uses funds flow from operations to analyze operating performance. Funds flow from operations represents cash flow from operations before changes in working capital and site restoration expenditures. Provident also reviews funds flow

from operations in setting monthly distributions and takes into account cash required for debt repayment and/or capital programs in establishing the amount to be distributed.

Funds flow from operations as presented does not have any standardized meaning prescribed by Canadian generally accepted accounting principles (GAAP) and therefore it may not be comparable with the calculations of similar measures for other entities. Funds flow from operations as presented is not intended to represent cash flow from operations or operating profits for the period nor should it be viewed as an alternative to cash provided by operating activities, net earnings or other measures of financial performance calculated in accordance with Canadian GAAP. All references to funds flow from operations throughout this report are based on cash provided by operating activities before changes in non-cash working capital and site restoration expenditures.

For the year ended December 31, 2007, funds flow from operations increased eight percent or $35.6 million to $468.3 million from $432.7 million for 2006 (per unit in 2007 - $2.04; 2006 - $2.20). COGP generated $204.3 million, USOGP $85.6 million, and Midstream $178.4 million of funds flow from operations during 2007. During 2006 COGP generated funds flow from operations of $185.3 million, USOGP $63.0 million, and Midstream $184.4 million.

Canadian oil and gas operations contributed funds flow from operations of $204.3 million in 2007, an increase of $19.0 million or 10 percent when compared with $185.3 million from 2006. The 2007 results reflect higher production from the acquisitions of Capitol Energy Resources Ltd. ("Capitol") on June 19, 2007 and Triwest Energy Inc. ("Triwest") on December 3, 2007, which are primarily light/medium crude oil production and a full year of production from the natural gas-weighted Rainbow assets acquired on August 31, 2006. In addition, incremental production from capital drilling programs in the core areas and higher realized crude oil and natural gas liquids prices contributed to the increase in funds flow from operations. These factors were offset by natural production declines, a lower realized natural gas price tied to the lower AECO natural gas index price, and reduced realized gains on financial derivative instruments compared to 2006.

The Midstream business unit added $178.4 million to 2007 funds flow from operations, compared with $184.4 million recorded in the year ended December 31, 2006. Midstream funds flow from operations reflects higher operating margins for all three business lines within the Midstream segment, offset by realized losses on financial derivative instruments, foreign exchange losses and higher interest costs due to increased corporate long-term debt balances.

The U.S. oil and gas operations provided increased funds flow from operations of $85.6 million in 2007, compared to $63.0 million in 2006, primarily driven by increased production due to oil and gas property acquisitions by the MLP in 2007, including the $1.5 billion USOGP natural gas asset acquisition in November 2007, partially offset by the impact of $13.9 million (2006 - $4.9 million) in cash payments, primarily in the first quarter of 2007, for unit based compensation related to the 2006 fiscal year. The expense was recorded as non-cash unit based compensation in 2006 and resulted in a decrease to funds flow from operations when paid in 2007.

Declared distributions in 2007 totaled $333.4 million, 77 percent of funds flow from operations, after distributions to non-controlling interests of $35.8 million. This compares to $283.5 million of declared distributions in 2006, 67 percent of funds flow from operations, after distributions to non-controlling interests of $6.5 million. In previous years, Provident has paid out between 67 percent and 102 percent of its annual funds flow from operations as distributions to unitholders.

Outlook

Provident's upstream and midstream operations are on track for 2008, as the Trust continues to focus on operational excellence to deliver on our base capital plan and realize additional upside through additional opportunities available in our asset base.

In the Canadian upstream business, the two acquisitions in 2007 (Capitol Energy and Triwest), the Rainbow acquisition in 2006, and Provident's existing assets provide Provident with approximately 1,000 identified drilling and recompletion opportunities. The program is well underway to drill 92 net wells in 2008, and to undertake a further 74 recompletions and workovers, with a total $134 million capital budget. Provident expects Canadian upstream production to average approximately 26,000 to 28,000 barrels of oil equivalent per day (boed) in 2008. Provident expects drilling and operating costs to ease somewhat in 2008, as activity in the sector levels off and we realize the benefit of the high quality assets acquired.

The U.S. upstream business anticipates a 2008 capital program of approximately U.S.$158 million with average production expected to be in the range of 20,900 to 22,800 boed (net of royalties). BreitBurn Energy Partners, L.P. (the "MLP") has a capital budget of approximately U.S.$120 million and plans to drill 206 net wells in 2008. MLP production is expected to be in the range of 18,300 to 20,000 boed (net of royalties) in 2008. BreitBurn Energy Company LP ("BreitBurn") has a capital budget of up to U.S.$38 million with plans to drill 12 net wells in 2008. BreitBurn production is expected to be in the range of 2,600 to 2,800 boed (net of royalties) in 2008.

Provident anticipates a capital program of $43 million for the Midstream business in 2008. Management anticipates that approximately $18 million will be invested in ongoing development of new underground storage caverns at Redwater, and $10 million will go toward further rail yard development. The 2008 sustaining capital budget has been raised to $13 million, and includes planned expenditures on operated and non-operated facilities. Assuming continued strong market conditions, Provident anticipates another successful year in 2008 for the Midstream business.

On February 5, 2008, Provident announced a strategic sales process of its U.S. oil and gas operations. Currently Provident owns approximately 22 percent of the MLP, including units held by the General Partner of which Provident indirectly owns approximately 96 percent. Provident also owns, through a wholly owned subsidiary, approximately 96 percent of BreitBurn. The book value of these investments at December 31, 2007 was approximately $425 million and the related tax basis is estimated to be approximately $100 million. It is Provident's intention to monetize its U.S. upstream investment, but there is no certainty that this process will result in any changes to Provident's ownership stakes in its U.S. holdings.

Strategic planning in 2008 will continue to focus on a review of Provident's Canadian businesses and initiatives to consider the most viable strategic and structural options available with the objectives of capturing and protecting unitholder value going forward. Certain options under consideration include the separation of the upstream and the midstream components of Provident's Canadian business. Provident cautions that the planning required before implementation will be lengthy and complex. There is no certainty that the planning will result in significant changes in Provident.

Distributions

The following table summarizes distributions paid as declared by the Trust since inception:

Record Date	Payment Date		Distribution Amount (Cdn$)	(US$)*
2007				
January 22, 2007	February 15, 2007	$	0.12	0.10
February 28, 2007	March 15, 2007		0.12	0.10
March 22, 2007	April 13, 2007		0.12	0.11
April 24, 2007	May 15, 2007		0.12	0.11
May 18, 2007	June 15, 2007		0.12	0.11
June 22, 2007	July 13, 2007		0.12	0.11
July 23, 2007	August 15, 2007		0.12	0.11
August 22, 2007	September 14, 2007		0.12	0.12
September 24, 2007	October 15, 2007		0.12	0.12
October 22, 2007	November 15, 2007		0.12	0.12
November 21, 2007	December 14, 2007		0.12	0.12
December 21, 2007	January 15, 2008		0.12	0.12
2007 Cash Distributions paid as declared		$	1.44	1.35
2006 Cash Distributions paid as declared			1.44	1.26
2005 Cash Distributions paid as declared			1.44	1.20
2004 Cash Distributions paid as declared			1.44	1.10
2003 Cash Distributions paid as declared			2.06	1.47
2002 Cash Distributions paid as declared			2.03	1.29
2001 Cash Distributions paid as declared – March 2001 – December 2001			2.54	1.64
Inception to December 31, 2007 – Distributions paid as declared		$	12.39	9.31

*Exchange rate based on the Bank of Canada noon rate on the payment date. The increase in distributions in U.S. dollars in 2007 is due to the increase in the Canadian dollar relative to the U.S. dollar.

For Canadian tax purposes, 2007 distributions were determined to be 94.8 percent taxable and 5.2 percent tax-deferred return of capital in the hands of Canadian unitholders. The 2006 comparables were 93.2 percent and 6.8 percent, respectively. Distributions received by U.S. resident unitholders in 2007 were classified as 97.6 percent qualified dividend and 2.4 percent tax deferred return of capital. The 2006 comparables were 97.7 percent and 2.3 percent respectively. In both Canada and the U.S., the tax-deferred portion would usually be treated as an adjustment to the cost base of the units. Unitholders or potential unitholders should consult their own legal or tax advisors as to their particular income tax consequences of holding Provident units.

Taxation of trust income

In 2007, future income tax expense includes $88.4 million relating to the enactment of Bill C-52, Budget Implementation Act 2007 by the Canadian government. This bill contains legislation to tax publicly traded trusts including Provident. The new legislation limits the tax deductibility of cash distributions after 2010 such that income taxes may become payable in the future. As a result of this legislation, the Trust is now required to record the future tax effect of the temporary differences on its flow through entities that are expected to reverse subsequent to 2010.

The Trust has estimated its future income taxes based on estimates of results of operations and tax pool claims and cash distributions in the future assuming no material change to the Trust's current organizational structure. The Trust's estimate of future income taxes does not incorporate any assumptions related to a change in organizational structure until such structures are given legal effect.

The Trust's estimate of its future income taxes will vary as do the Trust's assumptions pertaining to the factors described above, and such variations may be material.

The new legislation will not affect the Trust's cash flows from operations and accordingly the Trust's financial condition until 2011, based on our planned compliance with the legislated growth guidelines.
The Trust has approximately $1.5 billion in tax pools available to claim against taxable income (see "Taxes"). Provident plans to manage discretionary tax pool claims to defer payment of current taxes as long as possible. Provident has made estimates of taxability in future years based on a number of assumptions including: future product prices; future production and sales; future operating and product costs; future general and administrative costs; future capital expenditures; and general business conditions. Using these assumptions about future events which may or may not occur, Provident estimates that:

- current taxes on Canadian oil and gas operations would occur after 2016; and
- current taxes for midstream operations would occur in 2011.

Net income

Consolidated		Year ended December 31,	
($ 000s, except per unit data)	2007	2006	% Change
Net income	$ 30,434	$ 140,920	(78)
Per weighted average unit			
– basic and diluted [1]	$ 0.13	$ 0.72	(82)

[1] Based on weighted average number of trust units outstanding including the dilutive impact of the unit option plan, exchangeable shares and convertible debentures.

Consolidated		Year ended December 31,	
($ 000s)	2007	2006	% Change
COGP net income	$ 45,065	$ 83,453	(46)
USOGP net income	146,389	2,598	5,535
Total oil and gas net income	$ 191,454	$ 86,051	122
Midstream net (loss) income	(161,020)	54,869	-
Consolidated net income	$ 30,434	$ 140,920	(78)

Net income for the year ended December 31, 2007 decreased to $30.4 million compared to $140.9 million of net income in the comparable 2006 period. On a consolidated basis, favorable operating results were more than offset by a $281.0 million change in unrealized loss on financial derivative instruments and increased depletion, depreciation and accretion (DD&A) expense.

The COGP business segment's net income was $45.0 million, a $38.4 million reduction compared with the year ended December 31, 2006 net income of $83.4 million. An increase in EBITDA was more than offset by unrealized losses on financial derivative instruments and increased DD&A resulting from the acquisitions of Capitol and Triwest in 2007, and the Rainbow assets in 2006.

The Midstream segment recorded a net loss of $161.0 million as compared to net income of $54.9 million in the year ended December 31, 2006. The loss was primarily attributable to the impact of the commodity price risk management program. In 2007, Midstream generated a $76.9 million or 30 percent increase in gross operating margin, reflecting the positive price environment. Offsetting this was a $59.1 million increase in realized losses on financial derivative instruments and $192.9 million in unrealized losses on financial derivative instruments in 2007 representing a $124.6 million increase from 2006.

Additionally, the Midstream segment recognized future income tax expense of $94.2 million, an increase of $92.7 million from 2006, primarily due to the enactment in 2007 of legislation to tax publicly traded trusts in 2011.

For the year ended December 31, 2007, USOGP net income was $146.4 million as compared to $2.6 million in the year ended December 31, 2006. USOGP net income in 2007 includes a dilution gain of $260.3 million recognized at the time MLP units were issued to third parties to finance growth (see note 9 to consolidated financial statements). In addition, EBITDA increased by $19.9 million, or 26 percent, primarily due to the USOGP natural gas asset acquisition in the fourth quarter of 2007. Partially offsetting these factors was unrealized losses on financial derivative instruments of $110.0 million in 2007 compared to unrealized gains of $7.7 million in 2006.

The significant swing in Provident's net income year-over-year illustrates the extent to which net income figures are impacted by the requirement to "mark to market" all unrealized gains and losses associated with financial derivative instruments at a point in time and report these against current period income. Because Provident's commodity price risk management program extends up to five years into the future in the Midstream segment, net earnings can show substantial variation that is not necessarily related to current operations.

Reconciliation of non-GAAP measure

The Trust calculates earnings before interest, taxes, depletion, depreciation, accretion and other non-cash items (EBITDA) within its segment disclosure. EBITDA is a non-GAAP measure. A reconciliation between EBITDA and income before taxes and non-controlling interests follows:

EBITDA Reconciliation	Year ended December 31,		
($ 000s)	2007	2006	% Change
EBITDA	$ 545,096	$ 495,889	10
Adjusted for:			
Cash interest	(69,565)	(55,891)	24
Unrealized loss on financial derivative instruments	(324,284)	(43,314)	649
Dilution gain	260,324	-	-
Depletion, depreciation and accretion and other non-cash expenses	(376,192)	(279,188)	35
Income before taxes and non-controlling interests	$ 35,379	$ 117,496	(70)

Reconciliation of funds flow from operations to distributions	Year ended December 31,		
($ 000's, except per unit amounts)	2007	2006	% Change
Cash provided by operating activities	$ 464,455	$ 414,349	12
Change in non-cash operating working capital	(624)	13,693	-
Site restoration expenditures	4,424	4,622	(4)
Funds flow from operations	468,255	432,664	8
Distributions to non-controlling interests	(35,846)	(6,523)	450
Cash retained for financing and investing activities	(99,057)	(142,676)	(31)
Distributions to unitholders	333,352	283,465	18
Accumulated cash distributions, beginning of period	926,825	643,360	44
Accumulated cash distributions, end of period	$ 1,260,177	$ 926,825	36
Cash distributions per unit	$ 1.44	$ 1.44	-

Proportionate disclosures

Included in the consolidated financial results of Provident, and the USOGP segment in particular, are the consolidated results of the MLP and BreitBurn. At December 31, 2007 Provident owned approximately 22 percent of the MLP and 96 percent of BreitBurn. In accordance with generally accepted accounting principles in Canada and the United States, these investments are consolidated into Provident's results, with 100 percent of assets, liabilities, revenues and expenses recorded along with a corresponding non-controlling interest. In other sections of Management's Discussion and Analysis, information is presented in its consolidated form to correspond with the consolidated financial statements of Provident. This section presents a number of metrics that reflect Provident's proportionate interest in these investments.

Management uses proportionate information to analyze operating performance. The proportionate information as presented does not have any standardized meaning prescribed by Canadian GAAP and therefore may not be comparable with the calculation of similar measures for other entities. The proportionate information as presented is not intended to be viewed as an alternative to the corresponding measures of financial performance calculated in accordance with Canadian GAAP.

Oil and gas production (boed)	Year ended December 31, 2007	2006
COGP	26,509	24,018
USOGP [1]		
MLP (total)	9,518	1,279
Less: Non-controlling interest	(5,454)	(434)
Provident's interest	4,064	845
BreitBurn (total)	2,606	6,442
Less: Non-controlling interest	(112)	(287)
Provident's interest	2,494	6,155
Total USOGP - Provident's interest	6,558	7,000
Total - Provident's interest	33,067	31,018

[1] In the fourth quarter of 2006, approximately two-thirds of USOGP production and approximately one-half of USOGP reserves were transferred from BreitBurn to the MLP as part of the initial public offering of the MLP.

Funds flow from operations ($ 000's)	Year ended December 31, 2007	2006
COGP	$ 204,252	$ 185,328
Midstream	178,432	184,366
USOGP [1]		
MLP (total)	85,609	12,017
Less: Non-controlling interest	(49,118)	(4,068)
Provident's interest	36,491	7,949
BreitBurn (total)	10,821	63,555
Less: Non-controlling interest	(438)	(2,828)
Provident's interest	10,383	60,727
Other USOGP (corporate allocations)	(10,859)	(12,602)
Total USOGP - Provident's interest	36,015	56,074
Total - Provident's interest	$ 418,699	$ 425,768

[1] In the fourth quarter of 2006, approximately two-thirds of USOGP production and approximately one-half of USOGP reserves were transferred from BreitBurn to the MLP as part of the initial public offering of the MLP.

Capital expenditures ($ 000's)	Year ended December 31, 2007	2006
COGP	$ 146,209	$ 70,088
Midstream	31,904	66,008
USOGP [1]		
MLP (total)	27,936	2,604
Less: Non-controlling interest	(15,392)	(883)
Provident's interest	12,544	1,721
BreitBurn and other (total)	41,073	51,733
Less: Non-controlling interest	(1,769)	(2,302)
Provident's interest	39,304	49,431
Total USOGP - Provident's interest	51,848	51,152
Total - Provident's interest	$ 229,961	$ 187,248

[1] In the fourth quarter of 2006, approximately two-thirds of USOGP production and approximately one-half of USOGP reserves were transferred from BreitBurn to the MLP as part of the initial public offering of the MLP.

Long-term debt - revolving term credit facilities ($ 000's)	As at December 31, 2007	2006
COGP [1]	$ 230,999	$ 172,980
Midstream [1]	692,997	518,941
USOGP [2]		
MLP (total)	359,712	1,749
Less: Non-controlling interest	(280,627)	(593)
Provident's interest	79,085	1,156
BreitBurn (total)	9,124	9,323
Less: Non-controlling interest	(363)	(415)
Provident's interest	8,761	8,908
Total USOGP - Provident's interest	87,846	10,064
Total - Provident's interest	$ 1,011,842	$ 701,985

[1] Provident's credit facilities have been allocated for reporting purposes as 25 percent COGP and 75 percent Midstream.

[2] In the fourth quarter of 2006, approximately two-thirds of USOGP production and approximately one-half of USOGP reserves were transferred from BreitBurn to the MLP as part of the initial public offering of the MLP.

Taxes

Consolidated ($ 000s)	Year ended December 31, 2007	2006	% Change
Capital tax expense	$ 3,762	$ 1,314	186
Current and withholding tax expense	6,362	5,829	9
Future income tax expense (recovery)	30,487	(34,316)	-
	$ 40,611	$ (27,173)	-

Capital taxes in 2007 totaled $3.8 million, an increase from the $1.3 million expense recorded in 2006. The increase is due to greater production subject to the Saskatchewan resource surcharge.

The current and withholding tax expense of $6.4 million in 2007 compares to $5.8 million in 2006. The majority of these taxes arise from Provident's U.S.-based operations. The increase in current taxes was due to U.S.-based Midstream operations.

For the year ended December 31, 2007, future income tax expense was $30.5 million, compared with a recovery of $34.3 million in 2006. The 2007 expense includes $88.4 million relating to the second quarter enactment of legislation to tax publicly traded trusts in 2011.

For the year ended December 31, 2007, the total income tax expense was $40.6 million. Based on 2007 income before taxes of $71.0 million, the expected income tax expense was $23.3 million. The main reason for the larger than expected income tax expense is $88.4 million of future income taxes recorded as a result of the enactment of legislation to tax publicly traded trusts in 2011 (see "Taxation of trust income"). The offsetting difference between the expected expense and the total tax expense is primarily a result of deductions allowed when computing taxable income of the Trust for distributions made to unitholders. The Trust is a taxable entity under Canadian income tax law and is currently taxable only on income that is not distributed or distributable to the unitholders. If the Trust distributes all of its taxable income to the unitholders, no current provision for taxes is required by the Trust until 2011. Since inception, the Trust has distributed all of its taxable income to the unitholders. Additionally, interest and royalties are charged by the Trust to its subsidiaries, which are deductible in the computation of taxable income at the incorporated subsidiary level reducing tax pool claims in certain subsidiaries and potentially creating tax loss carry-forwards that result in future income tax recoveries.

Provident's tax pools available to shelter future income as at December 31, 2007 are estimated as follows:

As at December 31, 2007

($ 000s)		COGP		USOGP [1]		Midstream		Total
Intangibles	$	560,000	$	90,000	$	-	$	650,000
Tangibles		290,000		65,000		280,000		635,000
Non-capital losses		165,000		-		20,000		185,000
	$	1,015,000	$	155,000	$	300,000	$	1,470,000

[1] Non-Canadian tax pools

Provident also has capital losses of approximately $435 million which are available to reduce the tax effect of future capital gains.

Interest expense

Consolidated		Year ended December 31,			
($ 000s, except as noted)		2007		2006	% Change
Interest on bank debt	$	49,365	$	34,666	42
Weighted-average interest rate on bank debt		5.65%		5.30%	7
Interest on 8.75% convertible debentures		2,043		2,573	(21)
Interest on 8.0% convertible debentures		1,974		2,500	(21)
Interest on 6.5% convertible debentures		6,436		6,437	-
Interest on 6.5% convertible debentures		9,747		9,715	-
Total cash interest	$	69,565	$	55,891	24
Weighted average interest rate on all long-term debt		5.94%		5.81%	2
Debenture accretion and other non-cash interest expense		7,442		6,548	14
Total interest expense	$	77,007	$	62,439	23

Interest on bank debt increased in 2007 compared to 2006 due to increased capitalization including debt levels that resulted from the Capitol acquisition in the second quarter of 2007, the Rainbow asset acquisition in the third quarter of 2006 and the USOGP natural gas asset acquisition in the fourth quarter of 2007.

Financial instruments

Commodity price risk management program

For the year ended December 31, 2007 $80.7 million was recorded as a realized loss on financial derivative instruments due to the Commodity Price Risk Management Program (the Program) with $8.0 million related to the combined oil and gas operations and $79.0 million associated with the Midstream segment. In addition, $6.3 million was recorded as a realized gain related to settle foreign exchange based contracts.

In the oil and gas business units the realized loss in 2007 associated with crude oil totaled $17.6 million ($2.32 per barrel) and a realized gain of $9.6 million related to natural gas ($0.25 per gj). The combined total was a loss of $8.0 million or $0.57 per boe. In 2006 the Program recorded a realized gain of $1.9 million or $0.16 per boe with a realized loss of $5.7 million related to crude oil ($0.97 per barrel) and a realized gain of $7.6 million related to natural gas ($0.25 per gj).

In 2007 the Midstream segment recorded a realized loss of $79.0 million for NGL inventory price stabilization and frac-spread margin activities. In 2006 the Program recorded a realized loss of $15.4 million for these activities.

Realized gains on foreign exchange contracts related to the Program were $6.3 million. In 2006, the Program recorded a realized gain of $0.4 million for these activities.

On a per trust unit basis the opportunity cost of the Program increased to $0.35 per trust unit in 2007 from $0.07 per trust unit in 2006.

At December 31, 2007 the mark to market value of open contracts was in a net loss position of $378.0 million based upon commodity prices prevailing at that date. Under generally accepted accounting principles, these unrealized "mark-to-market" opportunity costs, which relate to financial derivative positions with effective periods ranging from 2008 through January 2013, are required to be recognized in the financial statements of Provident, affecting current period net income. These unrealized opportunity costs relate to financial derivative instruments which were entered into in order to manage commodity prices and protect future Midstream product margins. Fluctuations in the market value of these instruments have no impact on cash flow until the instruments are settled.

Provident's commodity price risk management program includes a consistent, active and disciplined hedging program that utilizes derivative instruments to provide for insurance against lower commodity prices and margins. The program provides support for stable cash distributions, capital programs and bank financing. The hedging strategy protects a percentage of Provident's oil and natural gas production against a decline in commodity prices while, with some products, allowing the Trust to participate in a rising commodity price environment. It provides price stabilization and protection of a percentage of inventory values and fractionation spread margin associated with the midstream services and marketing business unit. As well, the Provident hedging strategy reduces foreign exchange risk due to the exposure arising from the conversion of U.S. dollars into Canadian dollars.

Provident will continue to execute the program in 2008. The derivative instruments the Trust uses include puts, calls, costless collars, participating swaps, and fixed price products that settle against indexed referenced pricing.

Disclosure Controls and Procedures: U.S. Sarbanes-Oxley Act

In 2002, the United States Congress enacted the Sarbanes-Oxley Act (SOX), which stipulates that corporations publicly traded on U.S. financial exchanges must assess the effectiveness of their internal controls over financial reporting. As a foreign filer listed on the New York Stock Exchange, Provident is required to conduct the assessment. See "Management's Report on Internal Control Over Financial Reporting" and "Independent Auditors' Report".

Based on their evaluation as of December 31, 2007, Provident's chief executive officer and chief financial officer concluded that Provident's disclosure controls and procedures (as defined in Rules 13(a)-15(e) and 15(d)-15(e) under the United States Securities Exchange Act of 1934 (the Exchange Act) are effective to ensure that information required to be disclosed by Provident in reports that it files or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the United States Securities and Exchange Commission rules and forms. In addition, as of December 31, 2007, there were no changes in Provident's internal controls over financial reporting that occurred during 2007 that have materially affected, or are reasonably likely to materially affect its internal controls over financial reporting.

Provident will continue to periodically evaluate its disclosure controls and procedures and internal controls over financial reporting and will make any modifications from time to time as deemed necessary.

The Trust has undertaken a comprehensive review of the effectiveness of its internal control over financial reporting as part of the reporting, certification and attestation requirements of Section 404 of the U.S. Sarbanes-Oxley Act of 2002. For the year ended December 31, 2007, the company's internal controls were found to be operating free of any material weaknesses.

Acquisitions

In May 2007, BreitBurn Energy Partners L.P. (the "MLP") completed two oil and gas property acquisitions, one in Florida for cash consideration of USD $108.1 million and one in California for cash consideration of USD $92.5 million. The acquisitions were financed by the issue of units by the MLP to institutional investors. As a result of these unit issues, Provident's interest in the MLP decreased from approximately 66 percent to approximately 50 percent.

On June 19, 2007, Provident acquired Capitol Energy Resources Ltd. ("Capitol") for cash consideration of $467.5 million. Capitol, a public oil and gas exploration and production company active in the Western Canadian sedimentary basin, had as its principal asset a long-life resource play at Dixonville, Alberta. This play is being exploited using horizontal wells and will be further developed using waterflood technology. The acquisition was financed by the issuance of 29,313,727 trust units at $12.75 per unit and Provident's credit facility.

On November 1, 2007, the MLP acquired approximately $1.5 billion of natural gas, crude oil and related assets in Michigan, Indiana and Kentucky from Quicksilver Resources Inc. for U.S. $750 million in cash and approximately 21.3 million common units of the MLP. The acquisition is comprised of natural gas-weighted producing assets located primarily in the Michigan Antrim Shale. The cash portion of the purchase price was funded by a private placement of new MLP units and bank debt. As a result of this transaction, Provident's interest in the MLP has decreased from approximately 50 percent to approximately 22

percent. Provident continues to control the MLP through its 95.6 percent ownership of the general partner, resulting in consolidation of the MLP in accordance with generally accepted accounting principles in Canada and the United States.

On December 3, 2007, the Trust acquired Triwest Energy Inc. (Triwest), a privately held company with oil assets in southeast Saskatchewan. The Trust issued 6.3 million trust units (at an ascribed value of $76.6 million) and paid $2.3 million in cash as consideration for the acquisition. Triwest provides the Trust with approximately 1,300 barrels per day of oil production.

Goodwill

Goodwill represents the excess of the cost of an acquired enterprise over the net of the amounts assigned to assets acquired and liabilities assumed. The Capitol Energy acquisition in the second quarter of 2007 resulted in additional goodwill of $86.0 million. In 2005, the Midstream NGL Acquisition resulted in goodwill of $100.4 million. Goodwill of $330.9 million arose from COGP acquisitions in 2002 and 2004.

Goodwill is assessed for impairment at least annually, and if an impairment exists, it would be charged to income in the period in which the impairment occurs. Provident engaged an independent accounting firm to assist in performing an impairment test at year end. The impairment test includes, amongst other variables, a comparison of the net book value of the Trust's assets to the market value of the Trust's equity. Goodwill is not amortized.

Liquidity and capital resources

Consolidated		Year ended December 31,	
($ 000s)	2007	2006	% Change
Long-term debt - revolving term credit facility	$ 1,292,832	$ 702,993	84
Long-term debt - convertible debentures	256,440	285,792	(10)
Total debt	1,549,272	988,785	57
Equity (at book value)	1,708,665	1,542,974	11
Total capitalization at book value	$ 3,257,937	$ 2,531,759	29
Total debt as a percentage of total book value capitalization	48%	39%	23

Provident operates three business units with similar but not identical monthly cash settlement cycles. Midstream revenues are received at various times throughout the month. Provident's working capital position is affected by seasonal fluctuations that reflect commodity price changes, drilling cycles in its oil and gas operations and inventory balances in its Midstream business unit. Provident relies on funds flow from operations, external lines of credit and access to equity markets to fund capital programs and acquisitions.

As at December 31, 2007, Provident held non-bank sponsored asset-backed commercial paper with a face value of $6.5 million. These securities were previously classified as a component of cash and cash equivalents on the balance sheet. Provident has recorded an impairment write-down amounting to $1.8 million to reflect the fair value of these assets at December 31, 2007. The write-down is included in net income as part of foreign exchange loss and other. As at December 31, 2007 these securities have been classified on the balance sheet as other current assets ($1.1 million) and investments ($3.6 million) due to a reduction in market liquidity for these investments. The resolution of the liquidity issues will not have a significant impact on Provident's operations.

Contractual obligations

Consolidated		Payment due by period			
($ millions)	Total	Less than 1 year	1 to 3 years	4 to 5 years	More than 5 years
Long-term debt - revolving term credit facilities [1]	$ 1,483.4	$ 76.1	$ 1,407.3	$ -	$ -
Long-term debt - convertible debentures	343.0	39.1	58.0	245.9	-
Operating lease obligations	224.7	20.4	39.6	34.4	130.3
Total	$ 2,051.1	$ 135.6	$ 1,504.9	$ 280.3	$ 130.3

[1] The terms of the Canadian credit facility have a revolving three year period expiring on May 30, 2010. Provident can extend the revolving period by an additional year, no earlier than 90 days and no later than 30 days prior to the end of the first year of the applicable three year revolving period. If the lenders do not extend the revolving period, or Provident chooses not to extend, the credit facility will be terminated and the loan balance will become due and payable in full on the maturity date. Management intends to extend the revolving period beyond the current maturity date.

Long-term debt and working capital

As at December 31, 2007 Provident had drawn on 71 percent of its term credit facilities of $1,125 million and U.S. $ 737.7 million as compared to 63 percent drawn on its $925 million and U.S. $158 million term credit facilities as at December 31, 2006. The increase in the level of bank debt was due to the increased scale of operations primarily due to acquisitions.

At December 31, 2007 Provident had letters of credit guaranteeing Provident's performance under certain commercial and other contracts that totaled $35.9 million, increasing bank line utilization to 72 percent. The guarantees at December 31, 2006 totaled $31.9 million.

Provident's working capital decreased by $166.3 million from $55.8 million to a deficit of $110.5 million as at December 31, 2007. The significant decrease is primarily due to a $155.7 million increase in net current financial derivative instrument liabilities, a $151.6 million increase in accounts payable including distribution payable and current portion of convertible debentures, partially offset by increased accounts receivable of $147.4 million.

The ratio of long-term debt to funds flow from operations in 2007 was 3.3 to one, compared to 2.3 to one in 2006. Fourth quarter funds flow from operations in 2007 was $177.6 million. The ratio of debt to annualized fourth quarter funds flow from operations was 2.2 to one, as compared to 2006 fourth quarter annualized debt to funds flow from operations of 2.0 to one. The increase reflects debt issued in connection with the Capitol Energy and USOGP natural gas asset acquisitions.

Trust units

On May 24, 2007, the Trust issued 25,490,197 Subscription Receipts at a price of $12.75 per Subscription Receipt for total proceeds of $325 million ($308.3 million net of issue costs). On June 7, 2007, an additional 3,823,530 Subscription Receipts were issued at a price of $12.75 on exercise of the underwriter's over-allotment option, for additional proceeds of $48.8 million ($46.3 million net of issue costs). Each Subscription Receipt entitled the holder to receive one trust unit upon completion of the Capitol acquisition. The acquisition closed on June 19, 2007 at which time all the outstanding Subscription Receipts were converted into trust units. Proceeds from the issue were used to fund the Capitol acquisition.

On December 3, 2007 the Trust issued 6.3 million units (at an ascribed value of $76.6 million) as part of the consideration to acquire the outstanding shares of Triwest Energy Inc.

For the year ended December 31, 2007 the Trust issued 0.5 million units on conversion of convertible debentures (2006 – 1.3 million units). An additional 0.8 million units pursuant to the unit option plan were issued for the year ended December 31, 2007 (2006 – 0.9 million units). Under Provident's Premium Distribution, Distribution Reinvestment (DRIP) and Optional Unit Purchase Plan program 4.5 million units were elected in 2007 and were issued or are to be issued representing proceeds of $50.5 million (2006 – 3.0 million units for proceeds of $36.9 million).

At December 31, 2007 management and directors held approximately 0.9 percent of the outstanding trust units.

Non-controlling interest – USOGP operations

A non-controlling interest arose from Provident's June 15, 2004 acquisition of 92 percent of BreitBurn Energy Company L.P. (BreitBurn) of Los Angeles, California. Additional investments since June 2004 by Provident in BreitBurn have reduced the non-controlling interest percentage at December 31, 2007 to approximately 4.0 percent (2006 – 4.4 percent). Contributions by this non-controlling interest were nil in 2007 (2006 – $0.5 million). At December 31, 2007 the carrying amount of this non-controlling interest was $5.6 million (2006 - $3.9 million).

In the second quarter of 2006, a USOGP subsidiary began a land development project with a partner. The subsidiary has a 20 percent interest, with the partner holding 80 percent. Because the subsidiary stands to receive a majority share of the future proceeds, Provident is consolidating the results in its statements, with non-controlling interest. Contributions by the non-controlling interest total $3.9 million in 2007 (2006 - $3.7 million). At December 31, 2007 the carrying amount of this non-controlling interest was $5.4 million (2006 - $2.5 million).

In the fourth quarter of 2006, Provident's subsidiary, BreitBurn Energy Partners, L.P. (the "MLP") completed its initial public offering. BreitBurn transferred oil and gas properties comprising approximately half of its proved reserves and two thirds of its daily production to the MLP. The offering of 6.9 million common units at U.S. $18.50 per unit resulted in approximately 34 percent of the MLP held by partners not related to Provident. During the second quarter of 2007, the MLP issued 7.0 million common units to third parties for proceeds of $237.5 million. As a result of this transaction, Provident's interest in the MLP decreased from approximately 66 percent to approximately 50 percent, resulting in a dilution gain of $98.6 million recorded on the consolidated statement of operations. During the fourth quarter of 2007, the MLP issued 38.0 million units in conjunction with the USOGP natural gas asset acquisition. The cash proceeds and ascribed value of these issued units totaled $1,142.2 million. As a result of this transaction, Provident's interest in the MLP decreased from approximately 50 percent to approximately 22 percent, resulting in a dilution gain of $161.7 million recorded on the consolidated statement of operations. Provident continues to control the MLP through its 95.6 percent ownership of the general partner. The non-controlling interest balance increased by $1,119.4 million in 2007 reflecting the non-controlling interest ownership change from approximately 34 percent to approximately 78 percent. At December 31, 2007, the carrying value of this non-controlling interest was $1,089.1 million (2006 - $74.7 million).

	Year ended December 31,	
Non-controlling interests - USOGP ($ 000s)	2007	2006
Non-controlling interests, beginning of year	$ 81,111	$ 11,885
Net (loss) income attributable to non-controlling interest	(35,666)	2,995
Distributions to non-controlling interest	(35,846)	(6,523)
Investments by non-controlling interest	1,129,073	72,754
Foreign currency translation adjustment	(38,536)	-
Non-controlling interests, end of year	$ 1,100,136	$ 81,111
Accumulated (loss) income attributable to non-controlling interest	$ (30,152)	$ 5,514

Capital expenditures and funding

Consolidated	Year ended December 31,		
($ 000s)	2007	2006	% Change
Capital Expenditures and Funding			
Capital Expenditures			
Capital expenditures and reclamation fund contributions	$ (251,546)	$ (193,183)	30
Property acquisitions, net	(1,028,853)	(481,625)	114
Corporate acquisitions	(469,795)	(1,036)	45,247
Net capital expenditures	$ (1,750,194)	$ (675,844)	159
Funded By			
Funds flow from operations net of declared distributions to unitholders and non-controlling interest	$ 99,057	$ 142,676	(31)
Increase in long-term debt	534,215	117,385	355
Issue of trust units, net of cost; excluding DRIP	362,418	220,225	65
DRIP proceeds	50,491	36,851	37
Contributions by non-controlling interests	683,100	135,829	403
Change in working capital, including cash, sale of assets and change in investments	20,913	22,878	(9)
Net capital expenditure funding	$ 1,750,194	$ 675,844	159

Capital expenditures were funded by a combination of funds flow from operations, debt and equity issued from treasury through public offerings, the DRIP program and contributions by non-controlling interest.

Provident expects approximately $23 million in leasehold improvements and furniture and equipment associated with the head office move in 2008. Up to December 31, 2007, $20.9 million has been incurred. Of this amount, $13.6 million has been allocated to the COGP business unit and $7.3 million has been allocated to Midstream. See individual operating segment sections for discussion of other capital expenditures.

Non-cash unit based compensation

Non-cash unit based compensation includes expenses or recoveries associated with Provident's restricted and performance unit plan, unit option plan, unit appreciation rights and other unit based compensation plans. Provident accounts for the unit option plan using the fair value of the option at the time of issue. The other unit based compensation is recorded at the estimated fair value of the notional units granted. Compensation expense associated with the plans is recognized in earnings over the vesting period of each plan. The expense associated with each period is recorded as non-cash unit based compensation (a component of general and administrative expense). A portion is also allocated to operating expense. For the year ended December 31, 2007, Provident recorded unit based compensation expense of $30.9 million (2006 - $29.7 million) and made related cash payments of $15.7 million (2006 - $5.6 million). At December 31, 2007, the current portion of the liability totaled $22.2 million (December 31, 2006 - $18.2 million) and the long-term portion totaled $20.8 million (December 31, 2006 - $16.3 million).

COGP segment review

Crude oil and liquids price

COGP ($ per bbl)	Year ended December 31, 2007	2006	% Change
Oil per barrel			
WTI (US$)	$ 72.31	$ 66.22	9
Exchange rate (from US$ to Cdn$)	$ 1.07	$ 1.13	(5)
WTI expressed in Cdn$	$ 77.67	$ 74.83	4
Realized pricing before financial derivative instruments			
Light/Medium oil	$ 60.38	$ 57.18	6
Heavy oil	$ 41.85	$ 36.80	14
Natural gas liquids	$ 55.07	$ 51.91	6
Crude oil and natural gas liquids	$ 56.54	$ 52.38	8

The above realized prices are net of transportation expense.

For the year ended December 31, 2007 COGP's realized crude oil and natural gas liquids price, prior to the impact of financial derivative instruments, increased by eight percent to average $56.54 compared to $52.38 in 2006. The 2007 increase related to a nine percent higher US$ WTI crude oil price, narrower pricing differentials on all crude oil streams and a reduction in Provident's heavy oil volumes as a percentage of its oil production mix price, partially offset by a stronger Canadian dollar.

Natural gas price

COGP ($ per mcf)	Year ended December 31, 2007	2006	% Change
AECO monthly index (Cdn$ per mcf)	$ 6.59	$ 6.98	(6)
Corporate natural gas price per mcf before financial derivative instruments (Cdn$)	$ 6.42	$ 6.66	(4)

The above prices are net of transportation expense.

For the year ended December 31, 2007 COGP's realized natural gas price, excluding financial derivative instruments, decreased four percent as compared to 2006, comparable to the decrease in the benchmark AECO monthly index price. Provident markets approximately 25 percent of its natural gas to aggregators and the remaining 75 percent is sold to the market on daily or monthly indices, receiving prices that are based on the heat content of the natural gas. Provident's realized prices and changes in prices will therefore differ from benchmark indices.

Production

COGP	Year ended December 31, 2007	2006	% Change
Daily production			
Crude oil - Light/Medium (bpd)	7,876	6,815	16
- Heavy (bpd)	1,921	2,057	(7)
Natural gas liquids (bpd)	1,316	1,401	(6)
Natural gas (mcfd)	92,378	82,469	12
Oil equivalent (boed) [1]	26,509	24,018	10

[1] Provident reports equivalent production converting natural gas to oil on a 6:1 basis.

For the year ended December 31, 2007, COGP production averaged 26,509 boed, a 10 percent increase compared to 24,018 boed in 2006. The increase is primarily a result of the two recent acquisitions, Capitol on June 19, 2007 and Triwest on December 3,

2007, the full year effect in 2007 of the acquisition of the Rainbow assets (Northwest Alberta) on August 31, 2006, and the production volumes added through drilling and optimization activities, partially offset by natural production declines. The Capitol acquisition became COGP's newest core area, Dixonville, and the Triwest acquisition has been rolled up into the Southeast Saskatchewan core area.

Production for 2007 was weighted 58 percent natural gas, 35 percent medium/light crude oil and natural gas liquids and seven percent heavy oil. This compared to 2006 production weighted 57 percent natural gas, 34 percent medium/light oil and natural gas liquids and nine percent heavy oil. Year-over-year, the change in mix reflected the two acquisitions of Capitol on June 19, 2007 and Triwest on December 3, 2007 which were primarily light/medium crude oil production, and the full year effect in 2007 of the August 31, 2006 acquisition of the Rainbow assets, which were primarily natural gas.

COGP's production summarized by core areas is as follows:

	Year ended December 31,		
COGP	2007	2006	% Change
Daily Production - by area (boed) [1]			
West Central Alberta	6,997	8,168	(14)
Southern Alberta	5,622	6,237	(10)
Northwest Alberta	4,905	1,545	217
Dixonville [2]	2,058	-	-
Southeast Saskatchewan	1,769	1,731	2
Southwest Saskatchewan	1,726	2,624	(34)
Lloydminster	3,418	3,622	(6)
Other	14	91	(85)
	26,509	24,018	10

(1) Provident reports equivalent production converting natural gas to oil on a 6:1 basis.

(2) Represents production from June 19, 2007 (date of Capitol Energy Resources Ltd. acquisition).

Internal development activities included 103 net wells drilled for the year ended December 31, 2007 with a 98 percent success rate. COGP's drilling activities in 2007 were more focused on crude oil compared to 2006. Provident's newest core area, Dixonville had a successful drilling program although there was some unexpected production tie-in delays from cold weather which resulted in some additional downtime. Optimization of the production and facilities are ongoing. Northwest Alberta's production for 2007 represented a full year of production from the Rainbow asset acquisition. Northwest Alberta's successful 2006/2007 winter drilling program resulted in additional production in the first half of the year that was offset by the impact of unfavorable weather in the fourth quarter of 2007 causing a unit compressor and pump jack failure. Southeast Saskatchewan had favorable production results from its optimization activities and better than expected results from oil well drilling activities. Drilling and production results from the Triwest assets exceeded internal expectations. Provident's other core areas remain active. In southern Alberta, Provident actively managed production declines through shallow gas well drilling. In Lloydminster, Provident was successful with its workover activities and reactivation of oil wells resulting in production increases that were offset by higher than expected declines. In West Central Alberta, Provident continues its strategy of farming out high risk exploration land to generate cash flow with minimal or no capital outlay.

Revenue and royalties

COGP ($ 000s except per boe and mcf data)		Year ended December 31, 2007		2006	% Change
Oil					
Revenue	$	202,909	$	169,852	19
Realized loss on financial derivative instruments		(7,905)		(3,193)	148
Royalties		(39,211)		(32,567)	20
Net revenue	$	155,793	$	134,092	16
Net revenue (per barrel)	$	43.57	$	41.41	5
Royalties as a percentage of revenue		19.3%		19.2%	
Natural gas					
Revenue	$	216,626	$	200,584	8
Realized gain on financial derivative instruments		9,633		7,564	27
Royalties		(41,154)		(42,200)	(2)
Net revenue	$	185,105	$	165,948	12
Net revenue (per mcf)	$	5.49	$	5.51	-
Royalties as a percentage of revenue		19.0%		21.0%	
Natural gas liquids					
Revenue	$	26,451	$	26,545	-
Royalties		(6,681)		(6,458)	3
Net revenue	$	19,770	$	20,087	(2)
Net revenue (per barrel)	$	41.16	$	39.28	5
Royalties as a percentage of revenue		25.3%		24.3%	
Total					
Revenue	$	445,986	$	396,981	12
Realized gain on financial derivative instruments		1,728		4,371	(60)
Royalties		(87,046)		(81,225)	7
Net revenue	$	360,668	$	320,127	13
Net revenue (per boe)	$	37.27	$	36.52	2
Royalties as a percentage of revenue		19.5%		20.5%	

Note: the above revenue, net revenue and net revenue per boe figures are presented net of transportation expenses.

For the year ended December 31, 2007 COGP production revenue was $446.0 million, an increase of 12 percent from $397.0 million in 2006. The increase in revenue was a result of the 10 percent increase in production and higher realized crude oil and natural gas liquids prices. The increase was partially offset by a lower realized natural gas price. Royalties as a percentage of revenue have remained relatively constant at 19.5 percent. The preceding factors, as well as the $1.7 million realized gain on financial derivative instruments compared to a $4.4 million gain in 2006, account for net revenue of $360.7 million in 2007, 13 percent higher than the $320.1 million recorded in 2006.

Net revenue per boe in 2007 increased two percent to $37.27 from $36.52 in 2006 resulting primarily from higher realized crude oil and natural gas liquids prices and a higher percentage of production from liquids, partially offset by a lower realized gas price and a decrease in the realized gain on financial derivative instruments.

Production expenses

COGP ($ 000s, except per boe data)		2007		2006	% Change
				Year ended December 31,	
Production expenses	$	112,387	$	97,626	15
Production expenses (per boe)	$	11.62	$	11.14	4

For the year ended December 31, 2007 production expenses increased 15 percent to $112.4 million from $97.6 million and increased by four percent on a per unit basis to $11.62 per boe from $11.14 per boe in the prior year. The increase was primarily due to the increase in production of 10 percent. On a per boe basis, operating expenses continued to increase in a number of categories including well servicing, maintenance, fluid hauling, and power and fuel. Cost increases included increased power costs in July and August 2007 driven by hot weather in Southern Alberta and West Central Alberta, increased road maintenance costs in Northwest Alberta due to significant wet weather during the summer months, and higher than expected ice road maintenance in the winter months. Cost increases in power and fuel, chemicals and well servicing reflect higher commodity prices and labour costs.

Operating netback

COGP ($ per boe)		2007		2006	% Change
				Year ended December 31,	
Netback per boe					
Gross production revenue	$	46.09	$	45.29	2
Royalties		(9.00)		(9.27)	(3)
Operating costs		(11.62)		(11.14)	4
Field operating netback		25.47		24.88	2
Realized gain on financial derivative instruments		0.18		0.50	(64)
Operating netback after realized financial derivative instruments	$	25.65	$	25.38	1

COGP operating netbacks have transportation expense netted against gross production revenue.

The 2007 field operating netback of $25.47 per boe was two percent above the $24.88 per boe for the prior year. This reflects COGP's increased realized crude oil and natural gas liquids prices and an increase in COGP's production mix of higher priced light/medium crude oil to 30 percent in 2007 from 28 percent in 2006 and a decrease in lower netback heavy oil to seven percent in 2007 from nine percent in 2006. This was partially offset by lower realized natural gas prices due to the decrease in benchmark AECO monthly index price and four percent per boe higher operating costs as explained above. Royalties, which are price sensitive, decreased by three percent on a boe basis reflecting lower natural gas prices. The 2007 operating netbacks after financial derivative instruments increased by one percent to $25.65 from $25.38 in the prior year due to the preceding factors as well as the realized gain on financial derivative instruments of $0.18 per boe compared to $0.50 per boe in the prior year.

General and administrative

COGP ($ 000s, except per boe data)		2007		2006	% Change
				Year ended December 31,	
Cash general and administrative	$	27,102	$	24,065	13
Non-cash unit based compensation		3,698		4,320	(14)
	$	30,800	$	28,385	9
Cash general and administrative (per boe)	$	2.80	$	2.75	2

For the year ended December 31, 2007, cash general and administrative expenses were $2.80 per boe, compared to $2.75 per boe in 2006. The increase in cash general and administrative expenses reflects additional provisions for short-term incentive compensation reflecting the performance of the Trust in relation to established benchmarks.

Capital expenditures

COGP ($ 000s)	Year ended December 31, 2007	2006
Capital expenditures - by category		
Geological, geophysical and land	$ 4,519	$ 4,508
Drilling and recompletions	113,425	56,807
Facilities and equipment	13,378	6,353
Other capital	14,887	2,420
Total additions	$ 146,209	$ 70,088
Capital expenditures - by area		
West central Alberta	$ 9,051	$ 11,280
Southern Alberta	13,079	17,619
Northwest Alberta	35,993	4,883
Dixonville	43,801	-
Southeast Saskatchewan	5,069	1,941
Southwest Saskatchewan	15,196	25,677
Lloydminster	9,235	7,262
Office and other	14,785	1,426
Total additions	$ 146,209	$ 70,088
Property acquisitions, net	$ 13,050	$ 483,633

In 2007, Provident's COGP business unit spent $131.4 million on capital expenditures before office and other capital costs. Internal development activities included 103 net wells drilled for the year ended December 31, 2007 with a 98 percent success rate. COGP's drilling activities in 2007 were more focused on crude oil compared to 2006. Provident spent $43.8 million in the newest core area, Dixonville, primarily on drilling and completion activities utilizing three drilling rigs in the third and fourth quarters of 2007, which resulted in 39.0 net wells drilled. Provident spent $36.0 million in Northwest Alberta, primarily on drilling and completion activities and facility work which included 27.6 net wells drilled, the infrastructure and tie-in activities associated with the 2006/2007 winter drilling program and preparation work to start the 2007/2008 winter drilling program. In the Southeast and Southwest Saskatchewan core areas, $20.3 million was spent which included 20.1 net wells drilled. At the beginning of the year, the drilling program was primarily focused on the Southwest Saskatchewan shallow gas drilling program, however as gas prices declined during the year, the shallow gas drilling program was reduced significantly and capital was shifted to oil drilling in Dixonville and to the Triwest assets and facility opportunities in other areas. Southeast Saskatchewan spending was focused on optimization activities and oil drilling activity including additional capital for the continuation of the drilling program on the Triwest assets. In Southern Alberta, $13.1 million was primarily spent on drilling activity and recompletions which included 9.9 net wells drilled and on facility upgrades and infrastructure work. In West central Alberta, $9.1 million was spent largely on non-operated drilling and completion activities which included 3.0 net wells drilled, facility and infrastructure work, and recompletion activities. In the Lloydminster core area, $9.2 million was spent primarily on drilling and recompletion activities which included 3.4 net wells drilled and facility work.

Additions to proved plus probable reserves before revisions through internal capital replaced approximately 44 percent of annual production.

In 2007, COGP also spent $13.1 million on property acquisitions primarily on acquiring additional working interests in Northwest Alberta and Southern Alberta.

In addition, $14.8 million was spent on office and other in 2007, primarily on office equipment and furniture for the new office space to be occupied in 2008.

Depletion, depreciation and accretion (DD&A)

COGP		Year ended December 31,	
($ 000s, except per boe data)	2007	2006	% Change
DD&A	$ 256,723	$ 168,953	52
DD&A (per boe)	$ 26.53	$ 19.27	38

The COGP DD&A rate of $26.53 per boe increased 38 percent for 2007 compared to $19.27 per boe in 2006. The increase was primarily as a result of the two acquisitions of Capitol and Triwest in 2007 and the impact of the Rainbow asset acquisition in the third quarter of 2006 into the full year of 2007. These recent COGP acquisitions differed from earlier acquisitions in that they included significant reserves that were not yet proved. Since depletion calculations are based on proved reserves, acquisitions with unproved reserves generally result in higher depletion rates. This phenomenon, combined with the higher cost of acquiring or drilling proved reserves in western Canada in an environment with higher commodity prices and increased drilling costs, will be reflected in the DD&A rate going forward.

In 2007, DD&A also includes accretion expense associated with asset retirement obligation of $2.5 million (2006 - $1.9 million).

As part of the reconciliation of Provident's financial statements to United States generally accepted accounting principles (U.S. GAAP), disclosed in note 19 to consolidated financial statements, the Trust has reflected additional depletion in 2007 of $181.6 million (2006 – $382.2 million) and a related future income tax recovery of $52.2 million (2006 - $114.7 million) as a result of the application of the U.S. GAAP ceiling test. These changes were not required under Canadian generally accepted accounting principles.

USOGP segment review

The USOGP business unit incorporates activities from certain Provident subsidiaries comprising an oil and gas production organization based in Los Angeles, California.

In October 2006, Provident, through its USOGP subsidiaries, completed its initial public offering ("IPO") of 6.9 million units at USD $18.50 per unit of BreitBurn Energy Partners, L.P. (the "MLP"). This master limited partnership (NASDAQ-BBEP) is a U.S. public, tax flow-through entity similar to Canadian royalty and income trusts such as Provident. These entities, however, are not affected by the new Canadian legislation taxing trust distributions commencing in 2011. Selected producing assets in the Los Angeles basin in California and in Wyoming were transferred to the MLP. The previously existing subsidiary ("BreitBurn"), of which Provident owns approximately 96 percent, continues to operate assets in the Los Angeles basin at West Pico and other areas, and the Orcutt field in the Santa Maria basin.

In May 2007, the MLP completed two oil and gas property acquisitions, one in Florida for cash consideration of USD $108.1 million and one in California for cash consideration of USD $92.5 million. The acquisitions were financed by the issue of 7.0 million common units by the MLP to institutional investors at an average price of USD $31.58 per unit. As a result of these unit issues, Provident's interest in the MLP decreased from approximately 66 percent to approximately 50 percent, resulting in a dilution gain of $98.6 million recorded in the consolidated statement of operations in the second quarter of 2007.

On November 1, 2007, the MLP completed the acquisition of natural gas, oil and related assets in Michigan, Indiana and Kentucky from Quicksilver Resources Inc. ("Quicksilver") in exchange for U.S. $750 million in cash and 21.3 million MLP units. The cash portion of the acquisition was partially financed through the issuance of 16.7 million MLP units, at U.S. $27.00 per unit. As a result of these unit issues, Provident's interest in the MLP decreased from approximately 50 percent to approximately 22 percent, resulting in a dilution gain of $161.7 million recorded in the consolidated statement of operations in the fourth quarter of 2007. Provident continues to control and consolidate the MLP.

The USOGP segment includes the consolidated results of 100 percent of the MLP and BreitBurn. Non-controlling interests are comprised mainly of the public ownership in the MLP, and to a lesser extent the ownership interests of the managers in the MLP and BreitBurn, as well as third party investment in USOGP's land development project which commenced in 2006.

Crude oil, natural gas liquids and natural gas pricing

USOGP	Year ended December 31,		
($ per bbl, except as noted)	2007	2006	% Change
Realized pricing before financial derivative instruments			
Light/medium oil and natural gas liquids (Cdn$ per bbl)	$ 65.54	$ 63.24	4
Natural Gas (Cdn $ per mcf)	$ 7.22	$ 6.58	10

Realized pricing of light/medium oil and natural gas liquids were four percent higher in 2007 when compared to 2006, equivalent to the increase in WTI, expressed in Canadian dollars, over the same period.

Realized natural gas pricing before financial derivative instruments was up 10 percent in 2007 when compared to 2006. The increase was primarily associated with the increase in Henry Hub pricing. In addition, the newly acquired Michigan properties have favorable natural gas supply/demand characteristics as the state has been importing an increasing percentage of its natural gas.

Production

	Year ended December 31,		
USOGP	2007	2006	% Change
Daily production - by product			
Crude oil - Light/Medium (bpd)	9,557	7,299	31
Natural gas liquids (bpd)	105	18	483
Natural gas (mcfd)	14,773	2,422	510
Oil equivalent (boed) [1]	12,124	7,721	57

[1] Provident reports equivalent production converting natural gas to oil on a 6:1 basis.

USOGP	2007	2006	% Change
		Year ended December 31,	
Daily Production - by area (boed) [1]			
Los Angeles	4,203	3,901	8
Santa Maria - Orcutt	1,555	1,491	4
Wyoming	2,554	2,329	10
Texas	349	-	-
Florida	1,099	-	-
Michigan/Indiana/Kentucky	2,364	-	-
	12,124	7,721	57

[1] Provident reports equivalent production converting natural gas to oil on a 6:1 basis.

USOGP production increased 4,403 boe per day or 57 percent in 2007 when compared to 2006. The increase is primarily attributable to acquisitions made by USOGP in 2007, which included fields in Los Angeles, Florida, Texas, Michigan, Indiana and Kentucky. Production from the MLP for the year ended December 31, 2007 was 9,518 boed, while production from BreitBurn was 2,606 boed.

Revenue and royalties

The following table outlines USOGP revenue and royalties by product line. The table excludes revenues earned from operating certain properties ($1.3 million in the year ended December 31, 2007 (2006 - $1.0 million)) on behalf of third parties. The table also excludes revenue from the sale of inventory acquired as part of the Florida acquisition in May 2007, amounting to $12.8 million in the year ended December 31, 2007.

USOGP	Year ended December 31,		
($ 000s, except per boe and mcf amounts)	2007	2006	% Change
Oil and natural gas liquids			
Revenue	$ 222,263	$ 169,322	31
Realized loss on financial derivative instruments	(7,959)	(2,505)	218
Royalties	(25,294)	(16,554)	53
Net revenue	$ 189,010	$ 150,263	26
Net revenue (per bbl)	$ 55.73	$ 56.26	(1)
Royalties as a percentage of revenue	11.4%	9.8%	
Natural gas			
Revenue	$ 38,930	$ 5,820	569
Royalties	(6,360)	(761)	736
Net revenue	$ 32,570	$ 5,059	544
Net revenue (per mcf)	$ 6.04	$ 5.72	6
Royalties as a percentage of revenue	16.3%	13.1%	
Total			
Revenue	$ 261,193	$ 175,142	49
Realized loss on financial derivative instruments	(7,959)	(2,505)	218
Royalties	(31,654)	(17,315)	83
Net revenue	$ 221,580	$ 155,322	43
Net revenue (per boe)	$ 51.65	$ 55.12	(6)
Royalties as a percentage of revenue	12.1%	9.9%	

Note: the above revenue, net revenue and net revenue per boe figures are presented net of transportation expenses. Per boe figures are calculated using sales volumes, which differ from production volumes due to changes in inventory levels at the Florida properties, acquired in the second quarter of 2007.

For the year ended December 31, 2007 revenue was 49 percent higher than the year ended December 31, 2006 primarily due to increases in sales volumes from the acquisitions. Royalties as a percentage of revenue have increased as royalties at the

Michigan, Wyoming, Texas and Florida properties are higher than those incurred at the Southern California operations. Net revenue for the year ended December 31, 2007 was 43 percent higher than the year ended December 31, 2006 due to all the acquisitions in 2007 and the higher crude oil and natural gas prices. These increases were partially offset by higher realized losses on financial derivative instruments in 2007 compared to 2006.

Production expenses

USOGP		Year ended December 31,	
($ 000s, except per boe amounts)	2007	2006	% Change
Production expenses	$ 81,699	$ 52,008	57
Production expenses (per boe)	$ 19.04	$ 18.45	3

Note: Per boe figures are calculated using sales volumes, which differ from production volumes due to changes in inventory levels at the Florida properties, acquired in the second quarter of 2007.

Production expenses increased 57 percent to $81.7 million in 2007 compared to $52.0 million in 2006. Production expenses per boe have increased three percent to $19.04 in 2007 from $18.45 in 2006. This change reflects both the increase in utilities and other costs and services driven by the high commodity price environment as well as higher operating cost crude oil wells that were returned to production to take advantage of continuing strong crude oil prices. These increases were largely offset by lower production costs per boe from the newly acquired Michigan properties.

Operating netback

USOGP		Year ended December 31,	
($ per boe)	2007	2006	% Change
USOGP oil equivalent netback per boe			
Gross production revenue	$ 60.88	$ 62.15	(2)
Royalties	(7.38)	(6.14)	20
Operating costs	(19.04)	(18.45)	3
Field operating netback	$ 34.46	$ 37.56	(8)
Realized loss on financial derivative instruments	(1.85)	(0.89)	108
Operating netback after realized financial derivative instruments	$ 32.61	$ 36.67	(11)

Note: Per boe figures are calculated using sales volumes, which differ from production volumes due to changes in inventory levels at the Florida properties, acquired in the second quarter of 2007.

USOGP operating netbacks remained strong throughout 2007 due to high commodity prices, partially offset by higher realized losses on financial derivative instruments when compared to 2006 and increased production costs and royalties.

General and administrative

USOGP		Year ended December 31,	
($ 000s, except per boe amounts)	2007	2006	% Change
Cash general and administrative	$ 45,188	$ 26,519	70
Non-cash unit based compensation	5,950	12,476	(52)
	$ 51,138	$ 38,995	31
Cash general and administrative (per boe)	$ 10.21	$ 9.41	9

For the year ended December 31, 2007, cash general and administrative expenses were $45.2 million (2006 – $26.5 million). 2007 cash general and administrative expense includes $13.9 million or $3.14 per boe (2006 - $5.0 million or $1.75 per boe) related to payments associated with unit based compensation. The expense was accrued in 2006 as non-cash unit based compensation, consequently there is an offsetting reduction in non-cash unit based compensation in 2007, when the payments were made. Excluding these payments, cash general and administrative expenses were $31.3 million or $7.07 per boe for the year ended December 31, 2007 compared to $21.5 million or $7.63 per boe for the same period in 2006. The increase was due

to increased costs associated with regulatory compliance as well as increased staffing levels required for the rapidly growing public MLP.

Non-cash unit based compensation for the year ended December 31, 2007 was $6.0 million (2006 - $12.5 million expense). Year-to-date 2007 cash payments related to unit based compensation were $13.9 million compared to $5.0 million in 2006. Payment of unit based compensation is recorded as cash general and administrative expense with an offsetting reduction in non-cash unit based compensation. Excluding this payment, non-cash unit based compensation was $19.9 million for the year ended December 31, 2007 (2006 - $17.5 million). The increase in expense in 2007 reflects higher staffing levels due to the acquisitions as well as strong MLP performance in 2007.

Capital expenditures

USOGP		Year ended December 31,		
($ 000s)		2007		2006
Capital expenditures - by category				
Geological, geophysical and land	$	1,715	$	104
Drilling and recompletions		42,196		30,943
Facilities and equipment		18,691		18,486
Other capital		6,407		4,804
Total additions	$	69,009	$	54,337
Property acquisitions, net	$	1,015,803	$	(2,008)

USOGP capital expenditures for the year ended December 31, 2007 totaled $69.0 million. Of this total, $58.8 million related to drilling, optimization and facility upgrades at Orcutt, Wyoming, Santa Fe Springs and the newly acquired Michigan properties.

In 2007, USOGP completed property acquisitions of $1,015.8 million. $115.6 million represents the Florida acquisition and $98.9 million was spent on an acquisition in California. An additional $37.6 million was directed at acquiring additional wells in Texas, Los Angeles and Wyoming. $763.7 million represents the cash portion of the USOGP natural gas asset acquisition.

Depletion, depreciation and accretion (DD&A)

USOGP		Year ended December 31,			
($ 000s, except per boe amounts)		2007		2006	% Change
DD&A	$	50,253	$	31,058	62
DD&A (per boe)	$	11.36	$	11.02	3

The USOGP's DD&A rate is low due to the long-lived nature of the assets. On a per boe basis the DD&A rate was up $11.36 or three percent in 2007 when compared to 2006. The change reflects higher depletion costs related to the recent producing property acquisitions.

Recent developments

USOGP continues to progress on its acquisition integration. The MLP expects to complete its system integration relating to the USOGP natural gas asset acquisition in the second quarter of 2008.

Midstream business segment review

The Midstream business

The Midstream business unit extracts, processes, stores, transports and markets natural gas liquids (NGL) for Provident and offers these services to third party customers. The Provident Midstream segment contains three business lines:

Empress East
Redwater West
Commercial Services

The Empress East business line is comprised of the following core assets:

- Approximately 2.0 Bcfd of extraction capacity at Empress, Alberta. This is the combination of 67.5 percent ownership of the 1.2 Bcfd capacity Provident Empress NGL Extraction plant, 12.4 percent ownership in the 1.1 Bcfd capacity ATCO Plant, 8.3 percent ownership in the 2.4 Bcfd capacity Spectra Plant and 33.0 percent ownership in the 2.7 Bcfd capacity BP Empress 1 Plant.

- 100 percent ownership of a 50,000 bpd debutanizer at Empress, Alberta.

- 50 percent ownership in the 130,000 bpd Kerrobert Pipeline and 2.5 mmbbl underground storage facility near Kerrobert, Saskatchewan which facilitates injection into the Enbridge Pipeline System. Along the Enbridge Pipeline System, Provident holds 18.3 percent ownership of a 300,000 barrel Superior Storage staging facility and 18.3 percent ownership of the 6,600 bpd Superior Depropanizer.

- In Sarnia, Ontario, 10.3 percent ownership of an approximately 150,000 bpd fractionator, 1.7 mmbbl of raw product storage capacity and 18 percent of 5.0 mmbbl of finished product storage and rail, truck and pipeline terminalling. An additional 0.5 mmbbls of specification product storage is also available in the Sarnia area.

- A propane distribution terminal at Lynchburg, Virginia.

- A rail car fleet of approximately 350 rail cars.

The Redwater West business line is comprised of the following core assets:

- 100 percent ownership of the Redwater NGL Fractionation Facility, incorporating a 65,000 bpd fractionation, storage and transportation facility that includes 12 pipeline receipt and delivery points, railcar loading facilities with direct access to CN rail and indirect access to CP rail, two propane truck loading facilities, six million gross barrels of salt cavern storage, and a 60,000 bpd condensate rail offloading facility with a 300 railcar storage yard. The facility can process high-sulphur NGL streams and is one of only two ethane-plus fractionation facilities in western Canada capable of extracting ethane from the natural gas liquids stream.

- Approximately 7,000 bpd of leased fractionation and storage capacity at other facilities.

- 43.3 percent direct ownership and 100 percent control of all products from the 38,500 bpd Younger NGL extraction plant located at Taylor in northeastern British Columbia. The Younger plant supplies local markets as well as Provident's Redwater plant near Edmonton.

- 100 percent ownership of the 565 kilometer proprietary Liquids Gathering System ("LGS") that runs along the Alberta-British Columbia border providing access to a highly active basin for liquids-rich natural gas exploration and exploitation. Provident also has long-term shipping rights on the Pembina Peace Pipeline that extends the product delivery transportation network through to the Redwater fractionation facility.

- A rail car fleet of approximately 485 rail cars.

The Commercial Services business line:

The Commercial Services business line includes services such as fractionation, storage, and loading at Provident's Redwater facility on a fee basis. It also includes pipeline tariff income from Provident's ownership of the Liquids Gathering System in Northwest Alberta which flows into Pembina's pipeline from LaGlace to Redwater. Provident also collects tariff income from its 50 percent ownership in the Kerrobert Pipeline which transports NGLs from Empress to Kerrobert for injection into the Enbridge pipeline for delivery to Sarnia. Further, Provident owns a debutanizer at its Empress facility, which removes condensate from the NGL mix for sale as a diluent to blend with heavy oil. This service is provided to a major energy company on a long term cost of service basis. Earnings from this business line of the Midstream segment have little direct exposure to market prices volatility and are thus relatively stable.

Long term contracts

At the Redwater facility, a significant portion of the available propane plus capacity is contracted through a long term fee for service arrangement with third parties.

In 2006 and early 2007, Provident commissioned a 60,000 bpd condensate rail off-loading terminal at Redwater, a significant portion of which is under long term contracts with two major energy producers.

The ethane produced from Provident's facilities at Empress and Redwater is largely sold under long term contracts.

Provident has a long term contract on a cost of service basis for the majority of its 50,000 bbl/d Empress debutanizer facility. Provident also has a long term contract for 500,000 barrels of specification product storage in the Sarnia area.

Also, see commitments disclosure in note 15 to the consolidated financial statements.

2007 Midstream business unit results can be summarized as follows:

	Year ended December 31,		
($ 000s)	2007	2006	% Change
Empress East Margin	$ 183,565	$ 133,549	37
Redwater West Margin	94,600	75,686	25
Commercial Services Margin	54,649	46,695	17
Gross operating margin	332,814	255,930	30
Realized loss on financial derivative instruments	(74,474)	(15,406)	383
Cash general and administrative expenses	(28,669)	(23,621)	21
Foreign exchange (loss) gain and other	(3,996)	2,728	-
Midstream EBITDA	$ 225,675	$ 219,631	3

Note: Certain comparative amounts have been reclassified to conform with the current year presentation.

Gross operating margin

The Empress East business line extracts NGLs from natural gas at the Empress straddle plants and sells finished products into markets in Central Canada and the Eastern United States. The margin in this business is determined primarily by the "frac spread ratio", which is the ratio between crude oil prices and natural gas prices. The higher the ratio, the better this business line will perform. There is also a differential between propane, butane and condensate prices and crude oil prices which can change prices received and margins realized for Midstream products separate from frac spread ratio changes. The 2007 margin was $183.6 million compared to $133.5 million in 2006. The increase reflects approximately 10 percent higher propane-plus prices and lower transportation related costs, partially offset by five percent lower propane-plus sales volumes. Also, the 2006 gross operating margin includes the impact of a $5.2 million repayment incurred under the fractionation spread support program.

The Redwater West business line purchases an NGL mix from various producers and fractionates it into finished products at the Redwater fractionation facility near Edmonton, Alberta. Because the feedstock for this business line is primarily NGL mix rather than natural gas, the frac spread ratio has a smaller impact on margin than in the Empress East business line. In 2007,

the margin for this business line was $94.6 million (2006 - $75.7 million). The increase in margin was primarily due to an increase in propane-plus sales volumes and a 10 percent increase in propane-plus prices.

The Commercial Services business line generates income from stable fee-for-service contracts to provide fractionation, storage, loading, and marketing services to upstream producers. Income from pipeline tariffs from Provident's ownership in NGL pipelines is also included in this business line. In 2007, the margin for this business line was $54.6 million (2006 - $46.7 million). The increase in the margin is due to increased revenue associated with the condensate loading/offloading facility at Redwater which operated for a full year in 2007.

Operations – Midstream NGL sales volumes

Midstream sold 120,785 bpd in 2007, up five percent when compared with 2006.

Earnings before interest, taxes, depletion, depreciation, accretion, and other non-cash items ("EBITDA") and funds flow from operations

For 2007, EBITDA increased $6.0 million or three percent from $219.6 million in 2006. A $76.9 million increase in gross operating margin as described above was tempered by a $59.1 million increase in realized losses on financial derivative instruments and higher cash general and administrative and other costs. The increased cost associated with the financial derivative instruments in 2007 is offset by the realized product margin during the year. Funds flow from operations for 2007 was $178.4 million, a decrease of $6.0 million below the $184.4 million in 2006. The decrease in funds flow from operations reflects the higher EBITDA offset by higher interest costs due to increased corporate long-term debt balances, and higher taxes.

Cash general and administrative expenses and other were $28.7 million for 2007 (2006 - $23.6 million) reflecting additional provisions for short-term incentive compensation due to the performance of the Trust in relation to established benchmarks.

Management uses EBITDA to analyze the operating performance of the Midstream business unit. EBITDA as presented does not have any standardized meaning prescribed by Canadian GAAP and therefore it may not be comparable with the calculation of similar measures for other entities. EBITDA as presented is not intended to represent operating funds flow from operations or operating profits for the period nor should it be viewed as an alternative to funds flow from operations from operating activities, net earnings or other measures of financial performance calculated in accordance with Canadian GAAP. All references to EBITDA throughout this report are based on earnings before interest, taxes, depletion, depreciation, accretion, and other non-cash items ("EBITDA").

Fractionation spread support program

As part of the December 2005 Midstream NGL Acquisition, the vendor agreed to provide a near-term fractionation spread support program. The program provides Provident with up to $75 million of support in 2006 and up to October 31, 2007 if the fractionation spread ratio is below historic levels. This program was intended to ensure that Provident achieves the long-term average fractionation spread ratio that the NGL business has attained historically. There was no activity under this agreement in 2007 or the last three quarters of 2006. In the first quarter of 2006, there was a repayment of $5.2 million that was received in the fourth quarter of 2005. The program has now expired.

Capital expenditures

Midstream capital expenditures in 2007 totaled $31.9 million. In 2007, $5.3 million was spent on a new condensate offloading and terminalling facility, expansion to the recently completed truck loading facilities, and continued development of cavern storage. In addition, $13.9 million was added to capitalized line-fill, $4.5 million was spent on sustaining capital requirements and $8.2 million was spent primarily on office furniture and equipment for the new office space to be occupied in 2008.

Foreign ownership

Based on information received from our transfer agent and financial intermediaries in January 2008, an estimated 85 percent of our outstanding trust units are held by non-residents. However, this estimate may not be accurate as it is based on certain assumptions and data from the securities industry that does not have a well-defined methodology to determine the residency of beneficial holders of securities.

The Trust qualifies as a Mutual Fund Trust under the Canadian Income Tax Act because substantially all the value of its asset portfolio is derived from non-taxable Canadian properties, comprised principally of royalties and interest on inter-company debt. Provident monitors on an ongoing basis the value of its asset portfolio to confirm that substantially all of the value of its asset portfolio is derived from non-taxable Canadian properties.

On September 17, 2003, Canadian unitholders approved an amendment to the Trust's Trust Indenture providing that residency restriction provisions need not be enforced while the Trust continues to qualify as a Mutual Fund Trust under Canadian tax legislation. To allow Provident to remain a Mutual Fund Trust and to execute a business plan that maximizes unitholder returns without regard to the types of assets the Trust may hold, the approved amendment provides for Provident's Board of Directors to have sole discretion to determine whether and when it is appropriate to reduce or limit the number of trust units held by non-residents of Canada.

Critical accounting policies

Provident's accounting policies are described in note 2 to the consolidated financial statements. Certain accounting policies are identified as critical accounting policies because they form an integral part of Provident's financial position. They also require management to make judgments and estimates based on conditions and assumptions that are inherently uncertain. These accounting policies could result in materially different results should the underlying assumptions or conditions change.

Management assumptions are based on Provident's historical experience, management's experience, and other factors that, in management's opinion, are relevant and appropriate. Management assumptions may change over time, as further experience is gained or as operating conditions change.

Details of Provident's critical accounting policies are as follows:

Property, plant and equipment

Provident follows the full cost method of accounting, whereby all costs associated with the acquisition and development of oil and natural gas reserves are capitalized. Utilization of the full cost method of accounting requires the use of management estimates and assumptions for amounts recorded for depletion and depreciation of property, plant and equipment as well as for the ceiling test.

The provision for depletion and depreciation is calculated using the unit of production method based on current production divided by Provident's share of estimated total proved oil and natural gas reserve volumes before royalties. The recoverability of a cost centre is tested by comparing the carrying value of the cost centre to the sum of the undiscounted cash flows expected from the cost centre. If the carrying value is not recoverable the cost centre is written down to its fair value.

Proved reserves are an estimate, under existing reserve evaluation polices, of volumes that can reasonably be expected to be economically recoverable under existing technology and economic conditions. Changes in underlying assumptions or economic conditions could have a material impact on Provident's financial results. To mitigate these risks, management utilizes McDaniel & Associates Consultants Ltd., an independent engineering firm, to evaluate Provident's Canadian reserves. For Provident's U.S. based assets, management utilizes Netherland, Sewell & Associates, Inc., and Schlumberger Data & Consulting Services, independent engineering firms, to evaluate reserves.

Estimates of future production, oil and natural gas prices and future costs used in the ceiling test are, by their very nature, subject to uncertainty and changes in underlying assumptions could have a material impact on Provident's financial results.

Asset retirement obligation

Under the asset retirement obligation (ARO) standard, the fair value of asset retirement obligations is recorded as a liability on a discounted basis, when incurred. The value of the related assets is increased by the same amount as the liability and depreciated over the useful life of the asset. Over time the liability is adjusted for the change in present value of the liability or as a result of changes to either the timing or amount of the original estimate of undiscounted future cash flows.

Asset retirement obligation requires that management make estimates and assumptions regarding future liabilities and cash flows involving environmental reclamation and remediation. Such assumptions are inherently uncertain and subject to change over time due to factors such as historical experience, changes in environmental legislation or improved technologies. Changes in underlying assumptions, based on the above noted factors, could have a material impact on Provident's financial results.

Change in accounting policies

Financial instruments and comprehensive income

Effective January 1, 2007, Provident adopted the requirements of the Canadian Institute of Chartered Accountants ("CICA") related to the new financial instruments accounting framework, which encompasses the following new CICA Handbook sections: 3855 Financial Instruments – Recognition and Measurement, 1530 Comprehensive income, and 3861 Financial Instruments – Disclosure and Presentation. The CICA Handbook section 3865 Hedges is effective January 1, 2007, however, Provident has elected not to apply hedge accounting, consistent with prior periods.

These new Handbook sections provide comprehensive requirements for the recognition and measurement of financial instruments, and introduce a new component of equity referred to as accumulated other comprehensive income ("AOCI"). In accordance with the transitional provisions of all of the new sections, the comparative interim consolidated financial statements have not been restated, except that the "Cumulative translation adjustment" has been reclassified to "Accumulated other comprehensive income".

Under these new standards, all financial instruments, including derivatives, are recognized on the Trust's Consolidated Balance Sheet. Derivatives are measured at fair value with unrealized gains and losses reported in net income. Investments are measured at fair value, with reference to published price quotations, and unrealized gains and losses are reported in AOCI. The Trust's other financial instruments (accounts receivable, accounts payable, and long-term debt) are measured at amortized cost using the effective interest rate method. Transaction costs are included with the associated financial instrument and amortized accordingly.

Several adjustments in the Trust's consolidated financial statements were required upon transition to the new financial instruments framework, which were the following:

Long-term debt and deferred financing charges

Prior to the adoption of the new standards, financing charges related to long-term debt were included in "Deferred financing charges" on the Trust's Consolidated Balance Sheet, and recognized in net income over the life of the debt.

Under the transitional provisions of Handbook section 3855 Financial Instruments – Recognition and Measurement, the Trust's long-term debt – revolving credit facilities is now recorded at amortized cost using the effective interest rate method. The related financing charges have been included in the cost of the long-term debt. As a result of these changes, "Deferred financing charges" of $3.0 million, and prepaid interest of $8.5 million, which were previously recorded as assets of the Trust, were reclassified to "Long-term debt – revolving credit facilities" on the Consolidated Balance Sheet. The accounting treatment for "Long-term debt – convertible debentures" is the same as in prior periods, except that related deferred financing charges are now included in the carrying amount. Deferred financing charges of $9.4 million were reclassified to "Long-term debt – convertible debentures" on the Consolidated Balance Sheet.

Statement of comprehensive income

The consolidated financial statements now include a new Consolidated Statement of Comprehensive Income and Accumulated Other Comprehensive Income. Other comprehensive income includes foreign currency translation adjustments relating to self-sustaining foreign operations and unrealized gains and losses on available-for-sale investments, net of the related future income tax on those items.

Equity

In 2005, the CICA issued Section 3251 "Equity". This Section replaces Section 3250 "Surplus" and Section requires an entity to present separately each of the changes in equity during the period, including comprehensive income, as well as components of equity at the end of the period. This Section applies to interim and annual financial statements relating to fiscal years beginning on or after October 1, 2006. The application of this standard has not had a material impact on the Trust's financial statements.

Accounting changes

In 2006, the CICA released Section 1506 "Accounting Changes" which establishes criteria for changing accounting policies. Under the new section, voluntary changes in accounting policy are only made if they result in the financial statements providing reliable and more relevant information. Changes in accounting policy are applied retroactively unless it is impracticable to do so or the change in accounting policy is made on initial application of a primary source of GAAP, and that primary source of GAAP has specific transitional provisions. All material prior period errors are to be corrected retroactively. This section is effective for interim and annual financial statements for fiscal years beginning on or after January 1, 2007. The application of this standard has not had a material impact on the Trust's financial statements.

For recent accounting pronouncements, see note 3 to consolidated financial statements.

Business risks

The trust industry is subject to risks that can affect the amount of funds flow from operations available for distribution to unitholders, and the ability to grow. These risks include but are not limited to:

- capital markets risk and the ability to finance future growth; and
- the impact of Canadian governmental regulation on Provident, including the effect of the new tax on trust distributions.

The oil and natural gas industry is subject to numerous risks that can affect the amount of cash flow available for distribution to unitholders and the ability to grow. These risks include but are not limited to:

- fluctuations in commodity price, exchange rates and interest rates;
- government and regulatory risk in respect of royalty and income tax regimes;
- operational risks that may affect the quality and recoverability of reserves;
- geological risk associated with accessing and recovering new quantities of reserves;
- transportation risk in respect of the ability to transport oil and natural gas to market;
- marketability of oil and natural gas;
- the ability to attract and retain employees; and
- environmental, health and safety risks.

The midstream industry is also subject to risks that can affect the amount of cash flow available for distribution to unitholders and the ability to grow. These risks include but are not limited to:

- operational matters and hazards including the breakdown or failure of equipment, information systems or processes, the performance of equipment at levels below those originally intended, operator error, labour disputes, disputes with owners of interconnected facilities and carriers and catastrophic events such as natural disasters, fires, explosions,

fractures, acts of eco-terrorists and saboteurs, and other similar events, many of which are beyond the control of the Trust or Provident;

- the Midstream NGL assets are subject to competition from other gas processing plants, and the pipelines and storage, terminal and processing facilities are also subject to competition from other pipelines and storage, terminal and processing facilities in the areas they serve, and the gas products marketing business is subject to competition from other marketing firms;
- exposure to commodity price fluctuations;
- the ability to attract and retain employees;
- regulatory intervention in determining processing fees and tariffs; and
- reliance on significant customers.

Provident strives to minimize these business risks by:

- employing and empowering management and technical staff with extensive industry experience and providing competitive remuneration;
- adhering to a strategy of acquiring, developing and optimizing quality, low-risk reserves in areas where we have technical and operational expertise;
- developing a diversified, balanced asset portfolio that generally offers developed operational infrastructure, year-round access and close proximity to markets;
- adhering to a disciplined Commodity Price Risk Management Program to mitigate the impact that volatile commodity prices have on cash flow available for distribution;
- marketing crude oil and natural gas to a diverse group of customers, including aggregators, industrial users, well-capitalized third-party marketers and spot market buyers;
- marketing natural gas liquids and related services to selected, credit worthy customers at competitive rates;
- maintaining a competitive cost structure to maximize cash flow and profitability;
- maintaining prudent financial leverage and developing strong relationships with the investment community and capital providers;
- adhering to strict guidelines and reporting requirements with respect to environmental, health and safety practices; and
- maintaining an adequate level of property, casualty, comprehensive and directors' and officers' insurance coverage.

Unit trading activity

The following table summarizes the unit trading activity of the Provident units for each of the four quarters in the year ended December 31, 2007 on both the Toronto Stock Exchange and the New York Stock Exchange:

	Q1	Q2	Q3	Q4
TSE – PVE.UN (Cdn$)				
High	$ 13.02	$ 13.57	$ 12.99	$ 12.70
Low	$ 11.63	$ 12.38	$ 11.02	$ 9.60
Close	$ 12.50	$ 12.52	$ 12.64	$ 9.98
Volume (000s)	16,531	29,522	35,898	36,302
NYSE – PVX (US$)				
High	$ 11.24	$ 12.20	$ 12.73	$ 13.55
Low	$ 9.97	$ 10.76	$ 10.00	$ 9.65
Close	$ 10.83	$ 11.89	$ 12.69	$ 10.00
Volume (000s)	54,407	61,559	57,885	75,057

Forward-looking Statements

This MD&A contains forward-looking information or forward-looking statements under applicable securities legislation. These statements relate to future events or the Trust's future performance. Such forward-looking statements or information are provided for the purpose of providing information about management's current expectations and plans relating to the future. Readers are cautioned that reliance on such information may not be appropriate for other purposes, such as making investment decisions. All statements other than statements of historical fact are forward-looking statements. In some cases, forward-looking statements can be identified by terminology such as "may", "will", "should", "expect", "plan", "anticipate", "believe", "estimate", "predict", "potential", "continue", or the negative of these terms or other comparable terminology. Statements relating to "reserves" or "resources" are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the resources and reserves described can be profitably produced in the future. Forward looking statements or information in this MD&A include, but are not limited to, business strategy and objectives, reserve quantities and the discounted present value of future net cash flows from such reserves, net revenue, future production levels, capital expenditures, exploration plans, development plans, acquisition and disposition plans and the timing thereof, operating and other costs, royalty rates, budgeted levels of cash distributions and the performance associated with Provident's natural gas midstream, NGL processing and marketing business. Forward-looking statements or information are based on current expectations, estimates and projections that involve a number of risks and uncertainties which could cause actual events or results to differ materially from those anticipated by the Trust and described in the forward-looking statements or information. In addition, this MD&A may contain forward-looking statements attributed to third party industry sources. Undue reliance should not be placed on forward-looking statements or information, as there can be no assurance that the plans, intentions or expectations upon which they are based will occur. By its nature, forward-looking information involves numerous assumptions, known and unknown risks and uncertainties, both general and specific, that contribute to the possibility that the predictions, forecasts, projections and other forward-looking statements will not occur. Forward-looking statements in this MD&A include, but are not limited to, statements with respect to:

- the Trust's ability to benefit from the combination of growth opportunities and the ability to grow through the capital markets;
- the Trust's acquisition strategy, the criteria to be considered in connection therewith and the benefits to be derived therefrom;
- sustainability and growth of production and reserves through prudent management and acquisitions;
- the emergence of accretive growth opportunities;
- the ability to achieve a consistent level of monthly cash distributions;
- the impact of Canadian governmental regulation on the Trust;
- the existence, operation and strategy of the commodity price risk management program;
- the approximate and maximum amount of forward sales and hedging to be employed;
- changes in oil and natural gas prices and the impact of such changes on cash flow after hedging;
- the level of capital expenditures devoted to development activity rather than exploration;
- the sale, farming out or development using third party resources to exploit or produce certain exploration properties;
- the use of development activity and acquisitions to replace and add to reserves;
- the quantity of oil and natural gas reserves and oil and natural gas production levels;
- currency, exchange and interest rates;
- the performance characteristics of Provident's natural gas midstream, NGL processing and marketing business;
- the growth opportunities associated with the natural gas midstream, NGL processing and marketing business; and
- the nature of contractual arrangements with third parties in respect of Provident's natural gas midstream, NGL processing and marketing business.

Although the Trust believes that the expectations reflected in the forward-looking statements are reasonable, there can be no assurance that such expectations will prove to be correct. The Trust can not guarantee future results, levels of activity, performance, or achievements. Moreover, neither the Trust nor any other person assumes responsibility for the accuracy and completeness of the forward-looking statements. Some of the risks and other factors, some of which are beyond the Trust's control, which could cause results to differ materially from those expressed in the forward-looking information or forward-looking statements contained in this MD&A include, but are not limited to:

- general economic conditions in Canada, the United States and globally;
- industry conditions associated with the NGL services, processing and marketing business;
- fluctuations in the price of crude oil, natural gas and natural gas liquids;
- uncertainties associated with estimating reserves;
- royalties payable in respect of oil and gas production;
- interest payable on notes issued in connection with acquisitions;

- income tax legislation relating to income trusts, including the effect of new legislation taxing trust income;
- governmental regulation in North America of the oil and gas industry, including income tax and environmental regulation;
- fluctuation in foreign exchange or interest rates;
- stock market volatility and market valuations;
- the impact of environmental events;
- the need to obtain required approvals from regulatory authorities;
- unanticipated operating events which can reduce production or cause production to be shut-in or delayed;
- failure to realize the anticipated benefits of acquisitions;
- competition for, among other things, capital reserves, undeveloped lands and skilled personnel;
- failure to obtain industry partner and other third party consents and approvals, when required;
- risks associated with foreign ownership;
- third party performance of obligations under contractual arrangements; and
- the other factors set forth under "Business risks" in this MD&A.

Readers are cautioned that the foregoing list is not exhaustive of all possible risks and uncertainties. With respect to forwarding looking statements and forward looking information contained in this MD&A, the Trust has made assumptions regarding, among other things:

- future natural gas and crude oil prices;
- the ability of the Trust to obtain qualified staff and equipment in a timely and cost-efficient manner to meet demand;
- the regulatory framework regarding royalties, taxes and environmental matters in which the Trust conducts its business;
- the impact of increasing competition; and
- the Trust's ability to obtain financing on acceptable terms.
- the general stability of the economic and political environment in which the Trust operates;
- the timely receipt of any required regulatory approvals;
- the ability of the operator of the projects which the Trust has an interest in to operate the field in a safe, efficient and effective manner;
- field production rates and decline rates;
- the ability to replace and expand oil and natural gas reserves through acquisition, development of exploration;
- the timing and costs of pipeline, storage and facility construction and expansion and the ability of the Trust to secure adequate product transportation;
- currency, exchange and interest rates; and
- the ability of the Trust to successfully market its oil and natural gas products.

Readers are cautioned that the foregoing list is not exhaustive of all factors and assumptions which have been used. The forward-looking statements or information contained in this MD&A are made as of the date hereof and the Trust undertakes no obligation to update publicly or revise any forward-looking statements or information, whether as a result of new information, future events or otherwise unless required by applicable securities laws. The forward looking statements or information contained in this MD&A are expressly qualified by this cautionary statement.

Additional information

Additional information concerning Provident can be accessed under Provident's public filings at www.sedar.com and www.sec.gov/edgar.shtml, as well as on Provident's website at www.providentenergy.com.

Selected annual financial measures

($ 000s except per unit data)	2007	2006	2005
Revenue (net of royalties and financial derivative instruments)	$ 2,167,276	$ 2,187,253	$ 1,360,274
Net income	30,434	140,920	96,926
Net income per unit - basic and diluted	0.13	0.72	0.61
Total assets	5,758,792	3,370,919	2,792,270
Long-term financial liabilities [1]	1,863,512	1,098,040	930,756
Declared distributions per unit.	$ 1.44	$ 1.44	$ 1.44

[1] Includes long-term debt, asset retirement obligation, long-term financial derivative instruments and other long-term liabilities.

Quarterly table

Segmented information by quarter	2007				
($ 000s except for per unit and operating amounts)	First Quarter [1]	Second Quarter [1]	Third Quarter	Fourth Quarter	Year-to-Date
Financial - consolidated					
Revenue	$ 587,675	$ 504,468	$ 533,249	$ 541,884	$ 2,167,276
Funds flow from operations	$ 87,040	$ 98,503	$ 105,149	$ 177,563	$ 468,255
Net income (loss)	$ 43,093	$ (46,199)	$ (35,005)	$ 68,545	$ 30,434
Net income (loss) per unit - basic and diluted	$ 0.20	$ (0.21)	$ (0.14)	$ 0.28	$ 0.13
Unitholder distributions	$ 76,271	$ 80,236	$ 87,782	$ 89,063	$ 333,352
Distributions per unit	$ 0.36	$ 0.36	$ 0.36	$ 0.36	$ 1.44
Oil and gas production					
Cash revenue	$ 125,777	$ 139,453	$ 155,541	$ 186,891	$ 607,662
Earnings before interest, DD&A, taxes and other non-cash items	$ 54,736	$ 75,783	$ 82,523	$ 106,379	$ 319,421
Funds flow from operations	$ 47,636	$ 68,934	$ 72,799	$ 100,454	$ 289,823
Net (loss) income	$ (8,745)	$ 95,992	$ (26,375)	$ 130,582	$ 191,454
Midstream services and marketing					
Cash revenue	$ 453,272	$ 397,713	$ 433,950	$ 598,963	$ 1,883,898
Earnings before interest, DD&A, taxes and other non-cash items	$ 52,853	$ 35,974	$ 47,425	$ 89,423	$ 225,675
Funds flow from operations	$ 39,404	$ 29,569	$ 32,350	$ 77,109	$ 178,432
Net income (loss)	$ 51,838	$ (142,191)	$ (8,630)	$ (62,037)	$ (161,020)
Operating					
Oil and gas production					
Light/medium oil (bpd)	14,071	15,557	19,289	20,721	17,433
Heavy oil (bpd)	1,669	1,918	2,324	1,769	1,921
Natural gas liquids (bpd)	1,444	1,344	1,281	1,612	1,421
Natural gas (mcfd)	91,432	96,449	95,588	144,678	107,151
Oil equivalent (boed)	32,423	34,893	38,825	48,215	38,633
Average selling price net of transportation expense					
Light/medium oil per bbl (before realized financial derivative instruments)	$ 57.21	$ 59.44	$ 64.59	$ 69.70	$ 63.48
Light/medium oil per bbl (including realized financial derivative instruments)	$ 59.93	$ 59.39	$ 61.37	$ 62.34	$ 60.93
Heavy oil per bbl (before realized financial derivative instruments)	$ 34.69	$ 42.32	$ 45.34	$ 43.36	$ 41.85
Heavy oil per bbl (including realized financial derivative instruments)	$ 34.69	$ 42.32	$ 45.34	$ 43.36	$ 41.85
Natural gas liquids per barrel	$ 48.86	$ 52.56	$ 55.22	$ 51.39	$ 51.90
Natural gas per mcf (before realized financial derivative instruments)	$ 7.48	$ 7.25	$ 4.95	$ 6.53	$ 6.53
Natural gas per mcf (including realized financial derivative instruments)	$ 7.37	$ 7.18	$ 5.62	$ 6.92	$ 6.78
Midstream					
Midstream NGL sales volumes (bpd)	125,033	109,713	112,386	135,981	120,785

[1] Restated - see note 3 to third quarter 2007 interim consolidated financial statements.

Quarterly table

Segmented information by quarter ($ 000s except for per unit and operating amounts)	2006 First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Annual Total
Financial - consolidated					
Revenue	$ 553,706	$ 424,439	$ 661,022	$ 548,086	$ 2,187,253
Funds flow from operations	$ 78,906	$ 110,990	$ 120,089	$ 122,679	$ 432,664
Net income (loss)	$ 24,200	$ 21,371	$ 120,850	$ (25,501)	$ 140,920
Net income (loss) per unit - basic	$ 0.13	$ 0.11	$ 0.61	$ (0.12)	$ 0.72
Net income (loss) per unit - diluted	$ 0.13	$ 0.11	$ 0.58	$ (0.12)	$ 0.72
Unitholder distributions	$ 68,350	$ 68,572	$ 70,970	$ 75,573	$ 283,465
Distributions per unit	$ 0.36	$ 0.36	$ 0.36	$ 0.36	$ 1.44
Oil and gas production					
Cash revenue	$ 114,020	$ 125,744	$ 116,682	$ 125,135	$ 481,581
Earnings before interest, DD&A, taxes and other non-cash items	$ 64,313	$ 77,698	$ 67,750	$ 66,497	$ 276,258
Funds flow from operations	$ 52,813	$ 71,867	$ 61,471	$ 62,147	$ 248,298
Net income (loss)	$ 36,484	$ 25,980	$ 38,117	$ (14,530)	$ 86,051
Midstream services and marketing					
Cash revenue	$ 474,515	$ 367,624	$ 459,603	$ 447,244	$ 1,748,986
Earnings before interest, DD&A, taxes and other non-cash items	$ 32,813	$ 46,438	$ 65,958	$ 74,422	$ 219,631
Funds flow from operations	$ 26,093	$ 39,123	$ 58,618	$ 60,532	$ 184,366
Net income (loss)	$ (12,284)	$ (4,609)	$ 82,733	$ (10,971)	$ 54,869
Operating					
Oil and gas production					
Light/medium oil (bpd)	14,541	13,923	13,955	13,899	14,114
Heavy oil (bpd)	2,506	2,011	2,004	1,838	2,057
Natural gas liquids (bpd)	1,527	1,475	1,326	1,345	1,419
Natural gas (mcfd)	78,274	80,084	80,991	100,029	84,891
Oil equivalent (boed)	31,620	30,756	30,784	33,753	31,739
Average selling price net of transportation expense					
Light/medium oil per bbl (before realized financial derivative instruments)	$ 54.80	$ 69.76	$ 62.95	$ 54.59	$ 60.32
Light/medium oil per bbl (including realized financial derivative instruments)	$ 53.40	$ 68.00	$ 60.72	$ 55.56	$ 59.22
Heavy oil per bbl (before realized financial derivative instruments)	$ 22.87	$ 50.42	$ 48.15	$ 25.82	$ 36.80
Heavy oil per bbl (including realized financial derivative instruments)	$ 22.82	$ 50.42	$ 48.15	$ 25.82	$ 36.78
Natural gas liquids per barrel	$ 53.91	$ 54.20	$ 52.03	$ 47.49	$ 51.98
Natural gas per mcf (before realized financial derivative instruments)	$ 8.00	$ 6.10	$ 5.88	$ 6.71	$ 6.66
Natural gas per mcf (including realized financial derivative instruments)	$ 7.85	$ 6.41	$ 6.24	$ 7.12	$ 6.91
Midstream					
Midstream NGL sales volumes (bpd)	130,735	100,284	114,839	115,727	115,354

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of Provident is responsible for establishing and maintaining adequate internal control over financial reporting for the Trust. Under the supervision of our Chief Executive Officer and our Chief Financial Officer we have conducted an evaluation of the effectiveness of our internal control over financial reporting based on the Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on our assessment, we have concluded that as of December 31, 2007, our internal control over financial reporting was effective.

Management excluded from its assessment of the effectiveness of the Trust's internal control over financial reporting certain assets acquired from Quicksilver Resources, Inc. because they were acquired by a subsidiary of the Trust in a purchase business combination during 2007 (as further described in note 4 of the Trust's consolidated financial statements). Such total assets and total revenues represent approximately 26 percent and less than one percent respectively, of the related consolidated financial statement amounts as of and for the year ended December 31, 2007.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

The effectiveness of the Trust's internal control over financial reporting as of December 31, 2007, has been audited by PricewaterhouseCoopers LLP, independent auditors, as stated in their report which appears herein.

Thomas W. Buchanan
Chief Executive Officer

Mark N. Walker
Chief Financial Officer

Calgary, Alberta
March 18, 2008

MANAGEMENT'S RESPONSIBILITY FOR FINANCIAL STATEMENTS

The management of Provident is responsible for the information included in this Annual Report. The financial statements have been prepared in accordance with accounting principles generally accepted in Canada and in accordance with accounting policies detailed in the notes to the financial statements. Where necessary, the statements include amounts based on management's informed judgments and estimates. Financial information in the Annual Report is consistent with that presented in the financial statements.

PricewaterhouseCoopers LLP, Chartered Accountants, appointed by the unitholders, have audited the financial statements and conducted a review of internal accounting policies and procedures to the extent required by generally accepted auditing standards, and performed such tests as they deemed necessary to enable them to express an opinion on the financial statements.

The Board of Directors, through its Audit Committee, is responsible for ensuring that management fulfills its responsibility for financial reporting and internal control. The Audit Committee is composed of three independent directors. The Audit Committee reviews the financial content of the Annual Report and reports its findings to the Board of Directors for its consideration in approving the financial statements.

Thomas W. Buchanan
Chief Executive Officer

Mark N. Walker
Chief Financial Officer

Calgary, Alberta
March 18, 2008

PRICEWATERHOUSECOOPERS

PricewaterhouseCoopers LLP
Chartered Accountants
111 5 Avenue SW, Suite 3100
Calgary, Alberta
Canada T2P 5L3
Telephone +1 (403) 509 7500
Facsimile +1 (403) 781 1825

Independent Auditors' Report

To the Unitholders of Provident Energy Trust

We have completed integrated audits of the consolidated financial statements and internal control over financial reporting of Provident Energy Trust (the "Trust") as at December 31, 2007 and 2006. Our opinions, based on our audits, are presented below.

Consolidated financial statements

We have audited the accompanying consolidated balance sheets of Provident Energy Trust as at December 31, 2007 and December 31, 2006, and the related consolidated statements of operations and accumulated income, comprehensive income and accumulated comprehensive income and cash flows for each of the years then ended. These financial statements are the responsibility of the Trust's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits of the Trust's financial statements in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform an audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit of financial statements includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. A financial statement audit also includes assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Trust as at December 31, 2007 and December 31, 2006 and the results of its operations and its cash flows for each of the years then ended in accordance with Canadian generally accepted accounting principles.

Internal control over financial reporting

We have also audited Provident Energy Trust's internal control over financial reporting as at December 31, 2007, based on criteria established in *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Trust's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the effectiveness of the Trust's internal control over financial reporting based on our audit.

We conducted our audit of internal control over financial reporting in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. An audit of internal control over financial reporting includes obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the

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assessed risk, and performing such other procedures as we consider necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

As described in Management's Report on Internal Control Over Financial Reporting, management excluded certain assets acquired from Quicksilver Resources, Inc., ("QRI asset acquisition") from its assessment of the effectiveness of the Trust's internal control over financial reporting because they were acquired by a subsidiary of the Trust in a purchase business combination during 2007. We have also excluded the QRI asset acquisition from our audit of internal control over financial reporting. The total assets and total revenues associated with the QRI asset acquisition represent 26 percent and less than 1 percent respectively, of the related consolidated financial statement amounts as of and for the year ended December 31, 2007.

In our opinion, the Trust maintained, in all material respects, effective internal control over financial reporting as of December 31, 2007 based on criteria established in Internal Control — Integrated Framework issued by the COSO.

PricewaterhouseCoopers LLP

Chartered Accountants
March 18, 2008

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Comments by Auditor on Canada – U.S. reporting differences

In the United States, reporting standards for auditors require the addition of an explanatory paragraph (following the opinion paragraph) when there is change in accounting principles that has a material effect on the comparability of the Trust's financial statements, such as the changes described in Note 3 to the Consolidated Financial Statements. Our report is expressed in accordance with Canadian reporting standards which do not require a reference to such a change in accounting principles in the auditors' report when the change is properly accounted for and adequately disclosed in the financial statements.

PricewaterhouseCoopers LLP

Chartered Accountants
March 18, 2008

PROVIDENT ENERGY TRUST
CONSOLIDATED BALANCE SHEETS
Canadian dollars (000s)

	As at December 31, 2007	As at December 31, 2006
Assets		
Current assets		
Cash and cash equivalents	$ 6,820	$ 10,302
Accounts receivable	417,562	270,135
Petroleum product inventory	90,274	85,868
Prepaid expenses and other current assets	9,018	16,381
Financial derivative instruments (note 13)	2,289	12,909
	525,963	395,595
Investments	21,154	4,320
Deferred financing charges	-	12,351
Long-term financial derivative instruments (note 13)	-	171
Property, plant and equipment (note 5)	4,518,820	2,333,537
Intangible assets (note 6)	175,556	193,592
Goodwill (note 4)	517,299	431,353
	$ 5,758,792	$ 3,370,919
Liabilities		
Current liabilities		
Accounts payable and accrued liabilities	$ 424,468	$ 295,003
Cash distributions payable	25,100	21,506
Distributions payable to non-controlling interests	-	677
Current portion of convertible debentures (note 7)	19,198	-
Financial derivative instruments (note 13)	167,713	22,602
	636,479	339,788
Long-term debt - revolving term credit facilities (note 7)	1,292,832	702,993
Long-term debt - convertible debentures (note 7)	256,440	285,792
Asset retirement obligation (note 8)	80,900	49,614
Long-term financial derivative instruments (note 13)	212,581	43,336
Other long-term liabilities (note 11)	20,759	16,305
Future income taxes (note 12)	450,000	309,006
Non-controlling interests (note 9)		
USOGP operations	1,100,136	81,111
Subsequent event (note 16)		
Unitholders' equity		
Unitholders' contributions (note 10)	2,750,374	2,254,048
Convertible debentures equity component	18,213	18,522
Contributed surplus (note 11)	801	1,315
Accumulated other comprehensive (loss) income	(69,188)	(42,294)
Accumulated income	268,642	238,208
Accumulated cash distributions	(1,260,177)	(926,825)
	1,708,665	1,542,974
	$ 5,758,792	$ 3,370,919

The accompanying notes to the consolidated financial statements are an integral part of these statements.

On behalf of the Board of Directors:

M.H. (Mike) Shaikh, FCA
Director

Thomas W. Buchanan, CA
Director

PROVIDENT ENERGY TRUST
CONSOLIDATED STATEMENT OF OPERATIONS AND ACCUMULATED INCOME
Canadian dollars (000s except per unit amounts)

	Year ended December 31, 2007	2006
Revenue		
Revenue	$ 2,572,265	$ 2,244,107
Realized loss on financial derivative instruments	(80,705)	(13,540)
Unrealized loss on financial derivative instruments	(324,284)	(43,314)
	2,167,276	2,187,253
Expenses		
Cost of goods sold	1,605,782	1,471,171
Production, operating and maintenance	208,180	172,253
Transportation	28,120	19,786
Depletion, depreciation and accretion	351,364	249,139
General and administrative (note 11)	114,973	97,288
Interest on bank debt	51,660	34,666
Interest and accretion on convertible debentures	25,347	23,919
Amortization of deferred financing charges	-	3,854
Foreign exchange loss (gain) and other	6,795	(2,319)
Dilution gain (note 9)	(260,324)	-
	2,131,897	2,069,757
Income before taxes and non-controlling interests	35,379	117,496
Capital tax expense	3,762	1,314
Current and withholding tax expense	6,362	5,829
Future income tax expense (recovery) (note 12)	30,487	(34,316)
	40,611	(27,173)
Net (loss) income before non-controlling interests	(5,232)	144,669
Non-controlling interests (note 9)		
USOGP operations	(35,666)	2,995
Exchangeable shares	-	754
Net income	30,434	140,920
Accumulated income, beginning of year	$ 238,208	$ 97,288
Accumulated income, end of year	$ 268,642	$ 238,208
Net income per unit – basic and diluted	$ 0.13	$ 0.72

The accompanying notes to the consolidated financial statements are an integral part of these statements.

PROVIDENT ENERGY TRUST
CONSOLIDATED STATEMENT OF CASH FLOWS
Canadian Dollars (000s)

	Year ended December 31, 2007	2006
Cash provided by operating activities		
Net income for the year	$ 30,434	$ 140,920
Add (deduct) non-cash items:		
Depletion, depreciation and accretion	351,364	249,139
Non-cash interest expense and other	10,290	6,357
Non-cash unit based compensation (note 11)	14,014	23,083
Unrealized loss on financial derivative instruments	324,284	43,314
Unrealized foreign exchange loss and other	3,372	418
Future income tax expense (recovery) (note 12)	30,487	(34,316)
Dilution gain (note 9)	(260,324)	-
Net (loss) income attributable to non-controlling interests	(35,666)	3,749
Funds flow from operations	468,255	432,664
Site restoration expenditures (note 14)	(4,424)	(4,622)
Change in non-cash operating working capital	624	(13,693)
	464,455	414,349
Cash provided by financing activities		
Increase in long-term debt	534,215	117,385
Declared distributions to unitholders	(333,352)	(283,465)
Declared distributions to non-controlling interests	(35,846)	(6,523)
Issue of trust units, net of issue costs	412,909	257,076
Contributions by non-controlling interests (note 9)	683,100	135,829
Change in non-cash financing working capital	2,179	(154)
	1,263,205	220,148
Cash used for investing activities		
Capital expenditures	(247,122)	(190,433)
Capitol Energy acquisition (note 4)	(467,495)	-
Triwest Energy acquisition (note 4)	(2,300)	-
USOGP natural gas asset acquisition (note 4)	(763,652)	-
Acquisition of Midstream NGL business	-	(1,036)
Oil and gas property acquisitions, net (note 4)	(265,201)	(481,625)
Increase in investments	(5,450)	-
Proceeds on sale of assets	5,030	11,517
Change in reserve for future site reclamation (note 14)	-	1,872
Change in non-cash investing working capital	15,048	3,397
	(1,731,142)	(656,308)
Decrease in cash and cash equivalents	(3,482)	(21,811)
Cash and cash equivalents beginning of year	10,302	32,113
Cash and cash equivalents end of year	$ 6,820	$ 10,302
Supplemental disclosure of cash flow information		
Cash interest paid including debenture interest	$ 69,600	$ 56,036
Cash taxes paid	$ 13,741	$ 9,601

The accompanying notes to the consolidated financial statements are an integral part of these statements.

PROVIDENT ENERGY TRUST

CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME AND ACCUMULATED OTHER COMPREHENSIVE INCOME

Canadian Dollars (000s)

	Year ended December 31, 2007	2006
Net income	$ 30,434	$ 140,920
Other comprehensive (loss) income, net of taxes		
Foreign currency translation adjustments	(25,083)	(509)
Unrealized loss on available-for-sale investments (net of taxes of $262)	(1,811)	-
	(26,894)	(509)
Comprehensive income	$ 3,540	$ 140,411
Accumulated other comprehensive (loss) income, beginning of year	(42,294)	(41,785)
Other comprehensive (loss) income	(26,894)	(509)
Accumulated other comprehensive (loss) income, end of year	$ (69,188)	$ (42,294)
Accumulated income, end of year	268,642	238,208
Accumulated cash disributions, end of year	(1,260,177)	(926,825)
Retained earnings (deficit), end of year	(991,535)	(688,617)
Total retained earnings (deficit) and accumulated other comprehensive (loss) income, end of year	$ (1,060,723)	$ (730,911)

The accompanying notes to the consolidated financial statements are an integral part of these statements.

NOTES TO THE CONSOLIDATED FINANCIAL STATMENTS

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

(Tabular amounts in Cdn$ 000's, except unit and per unit amounts)

December 31, 2007

1. Structure of the Trust

Provident Energy Trust (the "Trust") is an open-end unincorporated investment trust created under the laws of Alberta pursuant to a trust indenture dated January 25, 2001, amended from time to time. The beneficiaries of the Trust are the unitholders. The Trust was established to hold, directly and indirectly, all types of petroleum and natural gas and energy related assets, including without limitation facilities of any kind, oil sands interests, electricity or power generating assets and pipeline, gathering, processing and transportation assets. The Trust commenced operations March 6, 2001.

Cash flow is provided to the Trust from properties owned and operated by Provident Energy Ltd. and directly and indirectly owned subsidiaries of the Trust ("Provident"). Cash flow is paid from Provident to the Trust by way of royalty payments, interest payments and principal debt repayments. The cash payments received by the Trust are subsequently distributed to the unitholders monthly.

2. Significant accounting policies

i) Principles of consolidation and investments

The consolidated financial statements include the accounts of the Trust and Provident, including the consolidated accounts of all wholly and partially owned subsidiaries, and are presented in accordance with Canadian generally accepted accounting principles. Investments subject to significant influence are accounted for using the equity method. Certain comparative numbers have been restated to conform to the current year presentation.

ii) Financial instruments

All financial instruments, including derivatives, are recognized on the Trust's Consolidated Balance Sheet. Derivatives are measured at fair value with unrealized gains and losses reported in net income. Investments, other than investments accounted for by the equity method, are measured at fair value, with reference to published price quotations, and unrealized gains and losses are reported in AOCI. The Trust's other financial instruments (accounts receivable, accounts payable, and long-term debt) are measured at amortized cost using the effective interest rate method. Transaction costs are included with the associated financial instruments and amortized accordingly (see note 3).

iii) Cash and cash equivalents

Cash and cash equivalents include short-term investments, such as money market deposits or similar type instruments, with an original maturity of three months or less when purchased.

iv) Property, plant & equipment and intangible assets

The Trust follows the full cost method of accounting for oil and natural gas exploration and development activities, whereby all costs associated with the acquisition and development of oil and natural gas reserves are capitalized. Such costs include lease acquisition, lease rentals on non-producing properties, geological and geophysical activities,

drilling of productive and non-productive wells, and tangible well equipment. Gains or losses on the disposition of oil and gas properties are not recognized unless the resulting change to the depletion and depreciation rate is 20 percent or more. All other property, plant and equipment, including midstream assets, are recorded at cost. Expenditures relating to renewals or betterments that improve the productive capacity or extend the life of property, plant and equipment are capitalized. Maintenance and repairs are expensed as incurred. Products required for line-fill and cavern bottoms are presented as part of property, plant and equipment and are stated at the lower of historic cost and net realizable value and are not depreciated.

a) Depletion, depreciation and accretion

The provision for depletion and depreciation for oil and natural gas assets is calculated, by cost centre, using the unit-of-production method based on current production divided by the Trust's share of estimated total proved oil and natural gas reserve volumes, before royalties. Production and reserves of natural gas and associated liquids are converted at the energy equivalent ratio of 6,000 cubic feet of natural gas to one barrel of oil. In determining its depletion base, the Trust includes estimated future costs for developing proved reserves, and excludes estimated salvage values of tangible equipment and the cost of unproved properties.

Midstream facilities, including natural gas liquids storage facilities and natural gas liquids processing and extraction facilities are carried at cost and depreciated on a straight-line basis over the estimated service lives of the assets, which range from 30 to 40 years. Intangible assets are amortized over the estimated useful lives of the assets, which range from two to 15 years. Capital assets related to pipelines are carried at cost and depreciated using the straight-line method over their economic lives.

b) Impairment

Oil and natural gas assets accounted for using the full cost method are subject to a ceiling test. The ceiling test calculation is performed by comparing the carrying value of the cost centre to the sum of the undiscounted proved reserve cash flows expected from the cost centre by country using future price estimates. If the carrying value is not recoverable, the cost centre is written down to its fair value. Fair value is determined by the future cash flows from the proved plus probable reserves discounted at the Trust's risk free interest rate. Any excess carrying value of the assets on the balance sheet above fair value would be recorded in depletion, depreciation and accretion expense as a permanent impairment.

For Midstream property, plant and equipment, and intangible assets, an impairment loss is recognized when the carrying amount exceeds the fair value.

v) Joint venture

Provident conducts many of its activities through joint ventures and the accounts reflect only Provident's proportionate interest in such activities.

vi) Inventory

Inventories of products are valued at the lower of average cost and net realizable value based on market prices.

vii) Goodwill

Goodwill, which represents the excess of cost of an acquired enterprise over the net of the amounts assigned to assets acquired and liabilities assumed, is assessed at least annually for impairment. To assess impairment, the fair value of the reporting unit is determined and compared to the book value of the reporting unit. If the fair value is less than the book value, then a second test is performed to determine the amount of the impairment. The amount of the impairment is determined by deducting the fair value of the reporting unit's assets and liabilities from the fair value of the reporting unit to determine the implied fair value of goodwill and comparing that amount to the book value of the reporting unit's goodwill. Any excess of the book value of goodwill over the implied fair value of goodwill is the impaired amount. Goodwill is not amortized.

viii) Asset retirement obligation

Under the asset retirement obligation ("ARO") standard the fair value of a liability for an ARO is recorded in the period where a reasonable estimate of the fair value can be determined. When the liability is recorded, the carrying amount

of the related asset is increased by the same amount of the liability. The asset recorded is depleted over the useful life of the asset. Additions to asset retirement obligations due to the passage of time are recorded as accretion expense. Actual expenditures incurred are charged against the obligation.

ix) Unit based compensation

The Trust uses the fair value method of valuing compensation expense associated with the Trust's unit option plan. Provident has applied this method to options issued after January 1, 2003, the effective date for implementing stock based compensation. Under the fair value method the amount to be recognized as expense is determined at the time the options are issued and is recognized in earnings over the vesting period of the options with a corresponding increase in contributed surplus.

The Trust has established other unit based compensation plans whereby notional units are granted to employees. The fair value of these notional units is estimated and recorded as part of general and administrative expenses with an offsetting amount to accrued liabilities or other long—term liabilities. A realization of the expense and a resulting reduction in cash provided by operating activities occurs when a cash payment is made.

x) Trust unit calculations

The Trust applies the treasury stock method to determine the dilutive effect of trust unit rights and trust unit options. Under the treasury stock method, outstanding and exercisable instruments that will have a dilutive effect are included in per unit - diluted calculations, ordered from most dilutive to least dilutive.

The dilutive effect of convertible debentures is determined using the "if-converted" method whereby the outstanding debentures at the end of the period are assumed to have been converted at the beginning of the period or at the time of issue if issued during the year. Amounts charged to income or loss relating to the outstanding debentures are added back to net income for the diluted calculation. The units issued upon conversion are included in the denominator of per unit - basic calculations from the date of issue.

xi) Income taxes

Provident follows the liability method for calculating income taxes. Differences between the amounts reported in the financial statements of the corporate subsidiaries and their respective tax bases are applied to tax rates in effect to calculate the future tax liability. The effect of any change in income tax rates is recognized in the current period income.

The Trust is a taxable entity under the Income Tax Act (Canada) and is currently taxable only on income that is not distributed or distributable to the unitholders. As the Trust distributes all of its taxable income to the unitholders and meets the requirements of the Income Tax Act (Canada) applicable to the Trust, no provision for current income taxes has been made in the Trust.

In 2007, the Canadian government enacted Bill C-52, Budget Implementation Act 2007. This bill contains legislation to tax publicly traded trusts, commencing in 2011. As a result of this legislation, the Trust records the future income tax effect of the temporary differences on its flow through entities that are expected to reverse subsequent to 2010.

xii) Revenue recognition

Revenue associated with the sales of Provident's natural gas, natural gas liquids ("NGLs") and crude oil owned by Provident is recognized when title passes from Provident to its customer.

Marketing revenues and purchased product are recorded on a gross basis when Provident takes title to product and has the risks and rewards of ownership.

Revenues associated with the services provided where Provident acts as agent are recorded on a net basis when the services are provided. Revenues associated with the sale of natural gas liquids storage services are recognized when the services are provided.

xiii) Foreign currency translation

The accounts of self-sustaining foreign operations are translated using the current rate method, whereby assets and liabilities are translated at period-end exchange rates, while revenue and expenses are translated using average rates for the period. Translation gains and losses related to self-sustaining operations are deferred and included as a component of accumulated other comprehensive income. A proportionate amount of the gain or loss is recognized in net income when there has been a reduction in the net investment.

The accounts of integrated foreign operations are translated using the temporal method, under which monetary assets and liabilities are translated at the period-end exchange rate, other assets and liabilities at the historical rates, and revenues and expenses at the rates for the period, except depreciation, depletion and accretion which is translated on the same basis as the related assets. Translation gains and losses are included in income in the period in which they arise.

xiv) Use of estimates

The preparation of financial statements requires management to make estimates based on currently available information. Actual results could differ from those estimated. In particular, management makes estimates for amounts recorded for depletion and depreciation of the property, plant and equipment, asset retirement obligation and future income taxes. The ceiling test uses factors such as estimated reserves, production rates, estimated future petroleum and natural gas prices and future costs. Due to the inherent limitations in metering and the physical properties of storage caverns and pipelines, the determination of precise volumes of natural gas liquids held in inventory at such locations is subject to estimation. Actual inventories of natural gas liquids can only be determined by draining of the caverns. By their very nature, these estimates are subject to measurement uncertainty and the effect on the financial statements of future periods could be material.

The estimation of oil and gas reserves is a subjective process. Forecasts are based on engineering data, projected future rates of production, estimated commodity prices, and the timing of future expenditures. The Trust expects reserve estimates to be revised based on the results of future drilling activity, testing, production levels, and economics of recovery based on cash flow forecasts.

3. Changes in accounting policies and practices

A. Changes in accounting policies

i) Financial instruments

Effective January 1, 2007, the Trust adopted the requirements of the Canadian Institute of Chartered Accountants ("CICA") related to the new financial instruments accounting framework, which encompasses the following new CICA Handbook sections: 3855 Financial Instruments – Recognition and Measurement, 1530 Comprehensive Income, and 3861 Financial Instruments – Disclosure and Presentation. The CICA Handbook section 3865 Hedges is effective January 1, 2007, however, the Trust has elected not to apply hedge accounting, consistent with prior periods.

These new Handbook sections provide comprehensive requirements for the recognition and measurement of financial instruments, and introduce a new component of equity referred to as accumulated other comprehensive income ("AOCI"). In accordance with the transitional provisions of all of the new sections, the comparative interim consolidated financial statements have not been restated, except that the "Cumulative translation adjustment" has been reclassified to "Accumulated other comprehensive income".

Under these new standards, all financial instruments, including derivatives, are recognized on the Trust's Consolidated Balance Sheet. Derivatives are measured at fair value with unrealized gains and losses reported in net income. Investments are measured at fair value, with reference to published price quotations, and unrealized gains and losses are reported in AOCI. The Trust's other financial instruments (accounts receivable, accounts payable, and long-term debt) are measured at amortized cost using the effective interest rate method. Transaction costs are included with the associated financial instrument and amortized accordingly.

In conjunction with the above standards, the CICA issued Section 3862 "Financial Instruments-Disclosures" and Section 3863 "Financial Instruments-Presentation". Section 3862 requires entities to provide disclosures in their

financial statements that enable users to evaluate the significance of financial instruments to the entity's financial position and performance. It also requires that entities disclose the nature and extent of risks arising from financial instruments and how the entity manages those risks. Section 3863 establishes presentation guidelines for financial instruments and non-financial derivatives and addresses the classification of financial instruments, from the perspective of the issuer, between liabilities and equity, the classification of related interest, dividends, losses and gains, and circumstances in which financial assets and financial liabilities are offset. These two sections are effective for annual and interim periods relating to fiscal years beginning on or after October 1, 2007. The Trust is currently evaluating the effect that these standards might have on the consolidated financial statements.

Several adjustments in the Trust's consolidated financial statements were required upon transition to the new financial instruments framework, which were the following:

Long-term debt and deferred financing charges

Prior to the adoption of the new standards, financing charges related to long-term debt were included in "Deferred financing charges" on the Trust's Consolidated Balance Sheet, and recognized in net income over the life of the debt.

Under the transitional provisions of Handbook section 3855 Financial Instruments – Recognition and Measurement, the Trust's long-term debt – revolving credit facilities is now recorded at amortized cost using the effective interest rate method. The related financing charges have been included in the cost of the long-term debt. As a result of these changes, "Deferred financing charges" of $3.0 million, and prepaid interest of $8.5 million, which were previously recorded as assets of the Trust, were reclassified to "Long-term debt – revolving credit facilities" on the Consolidated Balance Sheet. The accounting treatment for "Long-term debt – convertible debentures" is the same as in prior periods, except that related deferred financing charges are now included in the carrying amount. Deferred financing charges of $9.4 million were reclassified to "Long-term debt – convertible debentures" on the Consolidated Balance Sheet.

Comprehensive income

The consolidated financial statements now include a new Consolidated Statement of Comprehensive Income and Accumulated Other Comprehensive Income. Other comprehensive income includes foreign currency translation adjustments relating to self-sustaining foreign operations and unrealized gains and losses on available-for-sale investments, net of the related future income tax on those items.

ii) Equity

In 2005, the CICA issued Section 3251 "Equity". This Section replaces Section 3250 "Surplus" and establishes standards for the presentation of equity and changes in equity during the reporting period. The Section requires an entity to present separately each of the changes in equity during the period, including comprehensive income, as well as components of equity at the end of the period. This Section applies to interim and annual financial statements relating to fiscal years beginning on or after October 1, 2006. The application of this standard has not had a material impact on the Trust's financial statements.

iii) Accounting changes

In 2006, the CICA released Section 1506 "Accounting Changes" which establishes criteria for changing accounting policies. Under the new section, voluntary changes in accounting policy are only made if they result in the financial statements providing reliable and more relevant information. Changes in accounting policy are applied retroactively unless it is impracticable to do so or the change in accounting policy is made on initial application of a primary source of GAAP, and that primary source of GAAP has specific transitional provisions. All material prior period errors are to be corrected retroactively. This section is effective for interim and annual financial statements for fiscal years beginning on or after January 1, 2007. The application of this standard has not had a material impact on the Trust's financial statements.

B. Recent accounting pronouncements

i) Inventory

In June 2007, the CICA issued a new accounting standard, Section 3031 - Inventories, which replaces the existing standard for inventories, Section 3030. The main features of the new Section are as follows:

- measurement of inventories at the lower of cost and net realizable value;
- consistent use of either first-in, first-out or a weighted average cost formula to measure cost;
- reversal of previous write-downs to net realizable value when there is a subsequent increase to the value of inventories.

The new Section is effective for the Trust beginning January 1, 2008. The Trust is currently evaluating the effect that this standard might have on the consolidated financial statements.

ii) Capital disclosures

In 2006, the CICA released Section 1535 "Capital Disclosures" which addresses the requirements for an entity to disclose qualitative information about its objectives, policies and processes for managing capital. This section also establishes the requirement for an entity to disclose quantitative data about what it regards as capital as well as disclose whether it has complied with any externally imposed capital requirements and, if not, the consequences of such non-compliance. This section is effective for interim and annual financial statements relating to fiscal years beginning on or after October 1, 2007. The Trust is currently evaluating the effect that this standard might have on the consolidated financial statements.

iii) Goodwill and intangible assets

In February 2008, the CICA released section 3064 "Goodwill and intangible assets" which supersedes section 3062 "Goodwill and other intangible assets" and section 3450 "Research and development." This new section establishes standards for the recognition, measurement and disclosure of goodwill and intangible assets. This section applies to annual and interim financial statements relating to fiscal years beginning on or after October 1, 2008. The Trust does not expect the adoption of this standard to have a material impact on its financial statements.

4. Acquisitions

i) Acquisition of Triwest

On December 3, 2007, the Trust acquired the common shares of Triwest Energy Inc. ("Triwest"), for consideration of 6,251,149 trust units with an ascribed value of $76.6 million plus acquisition costs of $0.8 million and cash consideration of $1.5 million. Triwest was a privately held company with oil assets primarily in southeast Saskatchewan. The transaction was accounted for using the purchase method with the allocation of the purchase price as follows:

Net assets acquired and liabilities assumed		
Property, plant and equipment	$	115,719
Working capital, net		(2,757)
Bank debt		(11,122)
Asset retirement obligation		(752)
Future income taxes		(22,211)
	$	78,877
Consideration		
Acquisition costs	$	800
Cash		1,500
		2,300
Trust units issued		76,577
	$	78,877

ii) Acquisition of USOGP natural gas assets

On November 1, 2007, BreitBurn Energy Partners L.P. (the "MLP") completed the acquisition of certain assets from Quicksilver Resources Inc. ("Quicksilver") in exchange for cash consideration of U.S. $750 million and 21,347,972 MLP units reducing Provident's ownership in the MLP from approximately 50 percent to approximately 22 percent. The assets acquired include all of Quicksilver's natural gas, oil and related assets in Michigan, Indiana and Kentucky.

The transaction has been accounted for as an asset purchase with the allocation of cost as follows (in Canadian dollars):

Property, plant and equipment	$	1,453,697
Investments accounted for using the equity method		15,600
Intangible assets		5,131
Working capital, net		15
Asset retirement obligation		(10,230)
	$	1,464,213
Consideration		
Acquisition costs		12,952
Cash	$	750,700
		763,652
MLP units issued to Quicksilver		700,561
	$	1,464,213

The cash portion of the consideration was financed by the issue of 16,666,667 MLP units at U.S. $27.00 per unit (less underwriting fees and other costs of U.S. $8.7 million) and the MLP's credit facility.

iii) Acquisition of Capitol

On June 19, 2007, the Trust acquired Capitol Energy Resources Ltd. ("Capitol") for cash consideration of $467.5 million. Capitol was a public oil and gas exploration and production company active in the Western Canadian sedimentary basin. The transaction has been accounted for using the purchase method with the allocation of the purchase price as follows:

Net assets acquired and liabilities assumed		
Property, plant and equipment	$	522,707
Goodwill		85,946
Working capital, net		17,108
Bank debt		(53,100)
Financial derivative instruments		(621)
Asset retirement obligation		(1,752)
Future income taxes		(102,793)
	$	467,495
Consideration		
Acquisition costs	$	1,115
Cash		466,380
	$	467,495

The Capitol acquisition was financed by the issuance of 29,313,727 trust units at $12.75 per unit and Provident's credit facility.

iv) MLP acquisitions

In May 2007, BreitBurn Energy Partners L.P. (the "MLP") completed two oil and gas property acquisitions, one in Florida for cash consideration of U.S. $108.1 million and one in California for cash consideration of U.S. $92.5 million. The transactions were accounted for as asset purchases with the allocation of cost as follows (in Canadian dollars):

Property, plant and equipment	$	205,160
Intangible assets		3,591
Inventory		11,282
Other working capital, net		(821)
Asset retirement obligation		(4,708)
	$	214,504

The acquisitions were financed by the issue of units by the MLP to institutional investors (see note 9).

v) Acquisition of Rainbow assets

On August 31, 2006 Provident acquired a package of natural gas producing assets in the Rainbow and Peace River Arch areas of northwestern Alberta. The transaction was accounted for as an asset purchase with the allocation of the purchase price as follows:

Net assets acquired and liabilities assumed		
Property, plant and equipment	$	660,427
Asset retirement obligation		(1,903)
Future income taxes		(185,726)
	$	472,798
Consideration		
Acquisition costs	$	500
Cash		472,298
	$	472,798

The acquisition was financed by the issuance of 16,325,000 units at $13.85 per unit and Provident's credit facilities.

5. Property, plant and equipment

Year ended December 31, 2007		Cost		Accumulated depletion and depreciation		Net Book value
Oil and natural gas properties	$	4,977,958	$	1,215,499	$	3,762,459
Midstream assets		790,434		63,763		726,671
Office equipment		40,936		11,246		29,690
Total	$	5,809,328	$	1,290,508	$	4,518,820

Year ended December 31, 2006		Cost		Accumulated depletion and depreciation		Net Book value
Oil and natural gas properties	$	2,513,031	$	927,087	$	1,585,944
Midstream assets		781,092		42,143		738,949
Office equipment		17,070		8,426		8,644
Total	$	3,311,193	$	977,656	$	2,333,537

Costs associated with unproved properties and major development projects excluded from costs subject to depletion as at December 31, 2007 totaled $137.7 million (December 31, 2006 - $17.8 million). Midstream assets include $35.9 million (2006 - $22.0 million) for products required for line-fill and cavern bottoms.

An impairment test calculation was performed on property, plant and equipment at December 31, 2007 in which the estimated undiscounted future net cash flows based on estimated future prices associated with the proved reserves exceeded the carrying amount of oil and gas property, plant and equipment for each cost centre.

The following table outlines prices used in the impairment test at December 31, 2007:

Year		Oil $/bbl		Gas $/mcf		NGL $/bbl
2008	$	60.10	$	6.80	$	63.71
2009	$	59.38	$	7.60	$	62.00
2010	$	59.24	$	7.87	$	60.98
2011	$	58.11	$	8.11	$	59.39
2012	$	58.55	$	8.37	$	59.91
Thereafter [1]		2.00%		2.00%		2.00%

[1] Percentage change represents the increase in each year after 2012 to the end of the reserve life.

6. Intangible assets

December 31, 2007	Cost	Accumulated amortization	Net Book value
Midstream contracts and customer relationships	$ 183,100	$ 25,049	$ 158,051
Fractionation spread support agreement - Midstream	17,600	17,600	-
Other intangible assets - Midstream	16,308	2,566	13,742
U.S. oil and natural gas production related intangible assets	8,468	4,705	3,763
Total	$ 225,476	$ 49,920	$ 175,556

December 31, 2006	Cost	Accumulated amortization	Net Book value
Midstream contracts and customer relationships	$ 183,100	$ 12,842	$ 170,258
Fractionation spread support agreement - Midstream	17,600	9,258	8,342
Other intangible assets - Midstream	16,308	1,316	14,992
Total	$ 217,008	$ 23,416	$ 193,592

7. Long-term debt

	December 31, 2007	December 31, 2006
Revolving term credit facilities	$ 1,292,832	$ 702,993
Convertible debentures	275,638	285,792
Current portion of convertible debentures	(19,198)	-
	256,440	285,792
Total	$ 1,549,272	$ 988,785

i) Revolving term credit facilities

Provident has a $1,125 million term credit facility with a syndicate of Canadian chartered banks secured by midstream assets and by its Canadian oil and gas properties. Provident may draw on the credit facility by way of Canadian prime rate loans, U.S. base rate loans, banker's acceptances, letters of credit or LIBOR loans. At December 31, 2006 the facility totaled $925 million. In May 2007 the facility was increased to its current level of $1,125 million. At December 31, 2007, $925.3 million was drawn on this facility. Included in the carrying value at December 31, 2007 were financing costs of $1.3 million.

The terms of the credit facility have a revolving three year period expiring on May 30, 2010. Provident can extend the revolving period by an additional year, no earlier than 90 days and no later than 30 days prior to the end of the first year of the applicable three year revolving period. If the lenders do not extend the revolving period, or Provident chooses not to extend, the credit facility will be terminated and the loan balance will become due and payable in full on the maturity date.

In addition, Provident's U.S. subsidiaries have credit facilities with a borrowing base of U.S. $737.7 million with a syndicate of U.S. banks secured by oil and gas assets of the subsidiaries. Provident's U.S. subsidiaries may draw upon the facility by way of U.S. base rate loans, LIBOR loans or letters of credit. The facilities have a termination date of October 10, 2010. At December 31, 2007, $375.4 million was drawn on these facilities. Included in the carrying value at December 31, 2007 were financing costs of $6.6 million.

At December 31, 2007 the effective interest rate of the outstanding credit facilities was 5.9 percent (2006 – 5.2 percent). At December 31, 2007 Provident had $35.9 million in letters of credit outstanding (2006 - $31.9 million) that guarantee Provident's performance under certain commercial and other contracts.

ii) Convertible debentures

The Trust may elect to satisfy interest and principal obligations by the issue of trust units. For the twelve months ended December 31, 2007, $6.1 million of the face value of debentures were converted to trust units at the election of debenture holders (2006 - $15.4 million). Included in the carrying value at December 31, 2007 were financing costs of $7.0 million. The fair value of the convertible debentures at December 31, 2007 approximates the face value of the instruments. The following table details each outstanding convertible debenture.

Convertible Debentures	As at December 31, 2007		As at December 31, 2006			
($ 000s except conversion pricing)	Carrying Value [1]	Face Value	Carrying Value [1]	Face Value	Maturity Date	Conversion Price per unit [2]
6.5% Convertible Debentures	$ 140,515	$ 149,980	$ 142,860	$ 150,000	April 30, 2011	14.75
6.5% Convertible Debentures	91,460	99,024	93,134	99,024	Aug. 31, 2012	13.75
8.0% Convertible Debentures	24,465	25,109	24,402	25,114	July 31, 2009	12.00
8.75% Convertible Debentures	19,198	19,931	25,396	25,972	Dec. 31, 2008	11.05
	$ 275,638	$ 294,044	$ 285,792	$ 300,110		

[1] Excluding equity component of convertible debentures

[2] The debentures may be converted into trust units at the option of the holder of the debenture at the conversion price per unit

8. Asset retirement obligation

The Trust's asset retirement obligation is based on the Trust's net ownership in wells, facilities and the midstream assets and represents management's estimate of the costs to abandon and reclaim those wells, facilities and midstream assets as well as an estimate of the future timing of the costs to be incurred. Estimated cash flows have been discounted at the Trust's credit-adjusted risk free rate of seven percent and an inflation rate of two percent has been estimated for future years.

The total undiscounted amount of future cash flows required to settle asset retirement obligations related to oil and gas operations is estimated to be $613.1 million (2006 - $411.6 million). Payments to settle oil and gas asset retirement obligations occur over the operating lives of the assets estimated to be from two to 52 years.

The total undiscounted amount of future cash flows required to settle the midstream asset retirement obligations is estimated to be $166.1 million (2006 - $166.1 million). The estimated costs include such activities as dismantling, demolition and disposal of the facilities as well as remediation and restoration of the surface land. Payments to settle the midstream asset retirement obligations are expected to occur subsequent to the closure of the facilities and related assets. Settlement of these obligations is expected to occur in 29 to 40 years.

	Year ended December 31,	
($000s)	2007	2006
Carrying amount, beginning of year	$ 49,614	$ 41,133
Acquisitions	17,442	1,903
Change in estimate	14,561	6,793
Increase in liabilities incurred during the year	2,547	1,443
Settlement of liabilities during the year	(4,424)	(4,622)
Decrease in liabilities due to disposition	(654)	(946)
Accretion of liability	4,885	3,822
Foreign currency translation adjustments	(3,071)	88
Carrying amount, end of year	$ 80,900	$ 49,614

9. Non-controlling interests – USOGP

		Year ended December 31,		
		2007		2006
Non-controlling interests, beginning of year	$	81,111	$	11,885
Net (loss) income attributable to non-controlling interests		(35,666)		2,995
Distributions to non-controlling interests		(35,846)		(6,523)
Investments by non-controlling interests		1,129,073		72,754
Foreign currency translation adjustment		(38,536)		-
Non-controlling interests, end of year	$	1,100,136	$	81,111
Accumulated (loss) income attributable to non-controlling interests	$	(30,152)	$	5,514

A non-controlling interest arose from Provident's June 15, 2004 acquisition of 92 percent of BreitBurn Energy Company L.P. (BreitBurn) of Los Angeles, California. Additional investments since June 2004 by Provident in BreitBurn have reduced the non-controlling interest percentage at December 31, 2007 to approximately 4.0 percent (2006 – 4.4 percent). Contributions by this non-controlling interest were nil in 2007 (2006 – $0.5 million).

In the second quarter of 2006, a USOGP subsidiary began a land development project with a partner. The subsidiary has a 20 percent interest, with the partner holding 80 percent. Because the subsidiary stands to receive a majority share of the future proceeds, Provident is consolidating the results in its statements, with the partner's interest recorded as non-controlling interest. Contributions by the non-controlling interest total $3.9 million in 2007 (2006 - $3.7 million).

In the fourth quarter of 2006, Provident's subsidiary, BreitBurn Energy Partners, L.P. (the "MLP") completed its initial public offering. BreitBurn transferred oil and gas properties comprising approximately half of its proved reserves and two thirds of its daily production to the MLP. The offering of 6.9 million common units at U.S. $18.50 per unit resulted in approximately 34 percent of the MLP held by partners not related to Provident. During the second quarter of 2007, the MLP issued 7.0 million common units to third parties for proceeds of $237.5 million. As a result of this transaction, Provident's interest in the MLP decreased from approximately 66 percent to approximately 50 percent, resulting in a dilution gain of $98.6 million recorded on the consolidated statement of operations. During the fourth quarter of 2007, the MLP issued 38.0 million units in conjunction with the USOGP natural gas asset acquisition. The cash proceeds and ascribed value of these issued units totaled $1,142.2 million. As a result of this transaction, Provident's interest in the MLP decreased from approximately 50 percent to approximately 22 percent, resulting in an additional dilution gain of $161.7 million recorded on the consolidated statement of operations. The non-controlling interest balance increased by $1,119.4 million in 2007 reflecting the non-controlling interest ownership change from approximately 34 percent to approximately 78 percent. The Trust, through its 95.6 percent general partnership interest, continues to control and consolidate the MLP.

10. Unitholders' contributions

The Trust has authorized capital of an unlimited number of common voting trust units.

Trust units are redeemable at any time on demand by the holders thereof. Upon receipt of a redemption request by the Trust, the holder is entitled to receive a price per trust unit (the "Market Redemption Price") equal to the lesser of: (i) 90 percent of the simple average of the closing price of the trust units on the principal market on which the trust units are quoted for trading during the 10 trading day period commencing immediately after the date on which the trust units are surrendered for redemption; and (ii) the closing market price on the principal market on which the trust units are quoted for trading on the date that the trust units are surrendered for redemption.

The aggregate Market Redemption Price payable by the Trust in respect of any trust units surrendered for redemption during any calendar month shall be satisfied by way of a cash payment on the last day of the following month. Total cash payments for redemption are limited to an annual maximum of $250,000. Any excess over the maximum may be satisfied by distributing notes having an aggregate principal amount equal to the aggregate Market Redemption Price of the trust units tendered for redemption.

i) 2007 activity

On May 24, 2007, the Trust issued 25,490,197 Subscription Receipts at a price of $12.75 per Subscription Receipt for total proceeds of $325 million ($308.3 million net of issue costs). On June 7, 2007, an additional 3,823,530 Subscription Receipts were issued at a price of $12.75 on exercise of the underwriter's over-allotment option, for additional proceeds of $48.8 million ($46.3 million net of issue costs). Each Subscription Receipt entitled the holder to receive

one trust unit upon completion of the Capitol acquisition. The acquisition closed on June 19, 2007 at which time all the outstanding Subscription Receipts were converted into trust units. Proceeds from the issue were used to fund the Capitol acquisition.

On December 3, 2007 the Trust issued 6.3 million units (at an ascribed value of $76.6 million) as part of the consideration to acquire the outstanding shares of Triwest Energy Inc.

In 2007, the Trust issued 5.8 million units related to Provident's DRIP program, conversion of convertible debentures to units and units issued pursuant to Provident's Unit Option Plan. The net increase in unitholders' contributions associated with these activities was $65.2 million.

ii) 2006 activity

On July 31, 2006 the Trust issued 16,325,000 Subscription Receipts at a price of $13.85 per Subscription Receipt for total proceeds of $226.1 million ($214.2 million net of issue costs). Each Subscription Receipt entitled the holder to receive one trust unit upon completion of the Rainbow asset acquisition. The acquisition closed on August 31, 2006 at which time all the outstanding Subscription Receipts were converted into trust units. At that time, the holders of the Subscription Receipts were also entitled to $0.12 per trust unit, which is the equivalent of the August distribution paid in September. This payment was treated as a reduction to the proceeds received for the units issued through the Subscription Receipts to $13.73 per trust unit, reducing the amount attributed to Unitholders' contributions by $2.0 million. Proceeds from the issue were used to fund the Rainbow asset acquisition.

In 2006, the Trust issued 6.1 million units related to Provident's DRIP program, conversion of exchangeable shares to units, conversion of convertible debentures to units and units issued pursuant to Provident's Unit Option Plan. The net increase in unitholders' contributions associated with these activities was $70.1 million.

	Year ended December 31,					
	2007			2006		
Trust Units	Number of units		Amount (000s)	Number of units		Amount (000s)
Balance at beginning of year	211,228,407	$	2,254,048	188,772,788	$	1,971,707
Issued for cash	29,313,727		373,750	16,325,000		224,142
Issued to acquire Triwest Energy Inc.	6,251,149		76,577	-		-
Exchangeable share conversions	-		-	881,083		9,012
Issued pursuant to unit option plan	825,349		8,426	907,201		8,589
Issued pursuant to the distribution reinvestment plan	3,941,864		45,338	2,714,636		33,045
To be issued pursuant to the distribution reinvestment plan	525,822		5,153	300,134		3,806
Debenture conversions	548,455		6,270	1,327,565		15,689
Unit issue costs	-		(19,188)	-		(11,942)
Balance at end of year	252,634,773	$	2,750,374	211,228,407	$	2,254,048

The basic per trust unit amounts for 2007 were calculated based on the weighted average number of units outstanding of 229,939,158 (2006 – 196,627,060). The diluted per trust unit amounts for 2007 are calculated including no additional trust units (2006 – 286,957) for the dilutive effect of the unit option plan and the convertible debentures.

11. Unit based compensation

i) Restricted/Performance units

Certain employees of the Trust's Canadian and U.S. subsidiaries are granted restricted trust units (RTUs) and/or performance trust units (PTUs), both of which entitle the employee to receive cash compensation in relation to the value of a specific number of underlying notional trust or U.S. subsidiary units. The grants are based on criteria designed to recognize the long term value of the employee to the organization. RTUs vest evenly over a period of three years commencing at the grant date. Payments are made on the anniversary dates of the RTU to the employees entitled to receive them on the basis of a cash payment equal to the value of the underlying notional units. PTUs vest three years from the date of grant and can be increased to a maximum of double the PTUs granted or a minimum of nil PTUs depending on the Trust's performance vis-à-vis other trusts' performance based on certain benchmarks.

As of December 31, 2007 there were 1,408,196 RTUs and 4,441,152 PTUs outstanding (2006 – 571,423 RTUs and 1,704,234 PTUs). The fair value estimate associated with the RTUs and PTUs is expensed in the statement of

operations over the vesting period. At December 31, 2007, $12.7 million (2006 - $2.3 million) is included in accounts payable and accrued liabilities for this plan and $14.8 million (2006 - $13.3 million) is included in other long-term liabilities. The following table reconciles the expense recorded for RTUs and PTUs.

	Year ended December 31,	
	2007	2006
Cash general and administrative	$ 2,395	$ 1,021
Non-cash unit based compensation (included in general and administrative)	11,576	11,156
Production, operating and maintenance expense	1,247	939
	$ 15,218	$ 13,116

ii) Unit option plan

The Trust option plan (the "Plan") is administered by the Board of Directors of Provident. In October 2005, a restricted/performance unit program (see (i)) was approved. This program replaces the unit option plan. Unit options in existence will continue to be outstanding.

At December 31, 2007, the Trust had 1,279,169 options outstanding and exercisable with strike prices ranging between $10.49 and $12.14 per unit. The weighted average remaining contractual life of the options was 0.87 years and the weighted average exercise price was $11.04 per unit excluding average potential reductions to the strike prices of $1.77 per unit.

At December 31, 2006, the Trust had 2,114,808 options outstanding with strike prices ranging between $10.49 and $12.14 per unit. The weighted average remaining contractual life of the options was 1.96 years and the weighted average exercise price was $11.09 per unit excluding average potential reductions to the strike prices of $1.50 per unit. Of these outstanding options, 1,947,989 were exercisable with a weighted average price of $11.08.

The following table reconciles the movement in the contributed surplus balance.

	Year ended December 31,	
	2007	2006
Contributed surplus, beginning of the year	$ 1,315	$ 1,675
Non-cash unit based compensation (included in general and administrative)	57	203
Benefit on options exercised charged to unitholders' equity	(571)	(563)
Contributed surplus, end of year	$ 801	$ 1,315

iii) Unit appreciation rights

At December 31, 2007, the Trust's U.S. subsidiaries had unit appreciation rights (UARs) outstanding of 187,656 (2006 – 472,521) with a weighted average price of U.S. $9.58 (2006 – U.S. $8.41). Of these outstanding UARs, 148,336 (2006 – 81,852) were exercisable at a weighted average price of U.S. $9.46 (2006 – U.S. $8.46).

The fair value associated with the UARs is expensed in the statement of operations over the vesting period. At December 31, 2007, $0.8 million (2006 - $2.5 million) is included in accounts payable and accrued liabilities for this plan and nil (2006 - $0.1 million) is included in other long-term liabilities. The following table reconciles the expense recorded for UARs

	Year ended December 31,	
	2007	2006
Cash general and administrative	$ 2,113	$ 798
Non-cash unit based compensation (included in general and administrative)	(1,490)	1,246
	$ 623	$ 2,044

iv) Other unit based compensation

Pursuant to employment agreements between the Trust's U.S. subsidiaries and certain employees, the employees are eligible to receive cash compensation in relation to the value of a specified number of underlying notional units. The value of each notional unit is determined on the basis of a valuation of the U.S. subsidiaries as at the end of the fiscal period. At December 31, 2007 there were 3,061,137 notional units outstanding under the key employee plan (2006 – 2,755,566). There were 2,965,502 notional units outstanding under other USOGP unit based plans (2006 – 12,984,001). At December 31, 2007, $8.7 million (2006 - $13.4 million) is included in accounts payable and accrued liabilities for these plans, and $6.0 million (2006 - $2.9 million) is included in other long-term liabilities.

The following table reconciles the expense recorded for the other unit based compensation plans.

	Year ended December 31,	
	2007	2006
Cash general and administrative	$ 11,189	$ 3,807
Non-cash unit based compensation (included in general and administrative)	3,871	10,478
	$ 15,060	$ 14,285

12. Income taxes

In 2007, future income tax expense includes $88.4 million relating to the enactment of Bill C-52, Budget Implementation Act 2007 by the Canadian government. This bill contains legislation to tax publicly traded trusts including the Trust. As a result of this legislation, the Trust is now required to record the future tax effect of the temporary differences on its flow through entities that are expected to reverse subsequent to 2010.

Although the Trust believes it will be subject to additional tax under the new legislation, the estimated effective tax rate on temporary difference reversals after 2011 may change in future periods. As the legislation is new, future technical interpretations of the legislation could occur and could materially affect management's estimate of the future income tax liability.

The amount and timing of reversals of temporary differences will also depend on the Trust's future operating results, acquisitions and dispositions of assets and liabilities, and distribution policy. A significant change in any of the preceding assumptions could materially affect the Trust's estimate of the future tax liability.

Provident follows the liability method for calculating future income taxes. Under this method, future income tax assets and liabilities are recognized based on the estimated tax effects of temporary differences in the carrying value of assets and liabilities and their respective tax bases, using income tax rates substantively enacted on the consolidated balance sheet date:

	Year ended December 31,	
Future income taxes	2007	2006
Petroleum and natural gas properties, production facilities and other	$ 332,301	$ 266,156
Midstream facilities	117,699	42,850
	$ 450,000	$ 309,006

The income tax provision differs from the expected amount calculated by applying the Canadian combined federal and provincial income tax rate of 32.81 percent (2006 – 34.67 percent) as follows:

	Year ended December 31,	
	2007	2006
Expected income tax expense	$ 23,310	$ 40,736
Increase (decrease) resulting from:		
Future income tax expense relating to enactment of Bill C-52, Budget Implementation Act 2007	88,352	-
Non-deductible Crown charges and other payments	-	8,135
Federal resource allowance	-	(5,742)
Alberta Royalty Tax Credit	-	(173)
Income of the Trust and other	(73,045)	(70,999)
Capital Taxes	3,762	1,314
Witholding tax and other	3,425	3,308
Income tax rate changes	(5,193)	(3,752)
Income tax expense (recovery)	$ 40,611	$ (27,173)

13. Financial instruments

Financial instruments of the Trust carried on the consolidated balance sheet consist mainly of cash and cash equivalents, accounts receivable, current liabilities, commodity, foreign currency and interest rate contracts and long-term debt. Except as disclosed in note 7, as at December 31, 2007 and 2006, there were no significant differences between the carrying value of these financial instruments and their estimated fair value.

Substantially all of the Trust's accounts receivable are due from customers and joint venture partners in the oil and gas and midstream services and marketing industries and are subject to credit risk. The Trust partially mitigates associated credit risk by limiting transactions with certain counterparties to limits imposed by the Trust based on the Trust's assessment of the creditworthiness of such counterparties. The carrying value of accounts receivable reflects management's assessment of the associated credit risks. With respect to counterparties to financial instruments, the Trust partially mitigates associated credit risk by limiting transactions to counterparties with investment grade credit ratings and obtaining financial guarantees from certain counterparties.

Provident's commodity price risk management program is intended to minimize the volatility of commodity prices and to assist with stabilizing cash flow and distributions. Provident seeks to accomplish this through the use of financial instruments from time to time to reduce its exposure to fluctuations in commodity prices and foreign exchange rates.

With respect to financial instruments, Provident could be exposed to losses if a counterparty fails to perform in accordance with the terms of the contract. This risk is managed by diversifying the derivative portfolio among counterparties meeting certain financial criteria.

i) Commodity price

a) Crude oil

In 2007, Provident paid $17.6 million (2006 - $5.7 million) to settle various oil market based contracts on an aggregate volume of 3.4 million barrels (2006 – 2.1 million barrels). The estimated value of contracts in place if settled at market prices at December 31, 2007 would have resulted in an opportunity cost of $98.2 million (2006 – $7.2 million gain).

b) Natural Gas

In 2007, Provident received $9.6 million (2006 - $7.6 million) to settle various natural gas market based contracts on an aggregate of 16.7 million gigajoules ("gj") (2006 – 9.5 million gj's). The estimated value of contracts in place if settled at market prices at December 31, 2007 would have resulted in an opportunity cost of $18.0 million (2006 – $8.6 million gain).

c) Midstream

In 2007, Provident received $17.9 million (2006 – paid $0.6 million) to settle Midstream oil market based contracts on an aggregate volume of 1.2 million barrels (2006 - 1.5 million barrels) and paid $48.7 million (2006 - $27.1 million) to settle Midstream natural gas market based contracts on an aggregate volume of 25.3 million gj's (2006 – 15.3 million gj's). In addition, Provident paid $48.2 million (2006 – received $12.3 million) to settle Midstream NGL market based contracts on an aggregate volume of 7.2 million barrels (2006 – 2.5 million barrels). The estimated value of contracts in place if settled at market prices at December 31, 2007 would have resulted in an opportunity cost of $261.6 million (2006 – $68.8 million).

ii) Foreign exchange contracts

In 2007, Provident received $6.3 million to settle various foreign exchange based contracts (2006 - $0.4 million). The estimated value of contracts in place if settled at foreign exchange rates at December 31, 2007 would have resulted in an opportunity cost of $0.1 million (2006 – $0.1 million gain).

iii) Interest rate contracts

As at December 31, 2007 the estimated value of contracts in place settled at December 31 interest rates was an opportunity cost of $0.1 million (December 31, 2006 – nil).

The contracts in place at December 31, 2007 are summarized in the following tables:

COGP

Year	Product	Volume (Buy)Sell	Terms	Effective Period
2008	Crude Oil	250 Bpd	Puts US $63.75 per bbl	January 1 - December 31
		150 Bpd	Puts US $75.00 per bbl	January 1 - December 31
		1,000 Bpd	Puts US $67.50 per bbl	January 1 - December 31
		250 Bpd	Participating Swap US $60.00 per bbl (max to 75.3% above the floor price)	January 1 - December 31
		375 Bpd	Participating Swap US $65.00 per bbl (52.7% above the floor price)	January 1 - December 31
		450 Bpd	Participating Swap US $62.50 per bbl (max to 52.5% above the floor price)	January 1 - June 30
		450 Bpd	Participating Swap US $62.50 per bbl (67.8% above the floor price)	January 1 - June 30
		850 Bpd	Participating Swap US $65.00 per bbl (57.5% above the floor price)	January 1 - June 30
		850 Bpd	Participating Swap US $62.50 per bbl (max to 69.9% above the floor price)	January 1 - June 30
		300 Bpd	Participating Swap US $62.50 per bbl (max to 51% above the floor price)	July 1 - December 31
		625 Bpd	Participating Swap US $65.00 per bbl (54.25% above the floor price)	July 1 - December 31
		925 Bpd	Participating Swap US $62.50 per bbl (66% above the floor price)	July 1 - December 31
		325 Bpd	Participating Swap US $67.20 per bbl (70% above the floor price)	July 1 - December 31
	Natural Gas	1,000 Gjpd	Puts Cdn $6.00 per gj	January - March 31
		5,000 Gjpd	Participating Swap Cdn $6.48 per gj (max to 100% above the floor price)	January - March 31
		4,000 Gjpd	Participating Swap Cdn $7.00 per gj (52.8% above the floor price)	January - March 31
		2,000 Gjpd	Participating Swap Cdn $7.00 per gj (max to 70% above the floor price)	January - March 31
		4,000 Gjpd	Participating Swap Cdn $7.25 per gj (56% above the floor price)	January - March 31
		8,000 Gjpd	Participating Swap Cdn $7.50 per gj (70% above the floor price)	January - March 31
		8,000 Gjpd	Participating Swap Cdn $7.75 per gj (70% above the floor price)	January - March 31
		2,000 Gjpd	Participating Swap Cdn $8.00 per gj (max to 75.5% above the floor price)	January - March 31
		300 Gjpd	Participating Swap Cdn $7.60 per gj (53.5% above the floor price)	January 1 - June 30
		2,000 Gjpd	Participating Swap Cdn $6.00 per gj (max up to 85% above the floor price)	January 1 - October 31
		2,000 Gjpd	Participating Swap Cdn $7.50 per gj (max to 25% above the floor price)	January 1 - October 31
		900 Gjpd	Participating Swap Cdn $7.60 per gj (41% above the floor price)	January 1 - October 31
		2,000 Gjpd	Participating Swap Cdn $6.00 per gj (56% above the floor price)	April 1 - October 31
		2,000 Gjpd	Participating Swap Cdn $7.00 per gj (48.6% above the floor price)	April 1 - October 31
		1,000 Gjpd	Participating Swap Cdn $6.75 per gj (51% above the floor price)	April 1 - December 31
		1,000 Gjpd	Participating Swap Cdn $7.00 per gj (max up to 85% above the floor price)	April 1 - December 31
		1,000 Gjpd	Participating Swap Cdn $7.50 per gj (max to 23.5% above the floor price)	April 1 - December 31
		1,000 Gjpd	Participating Swap Cdn $6.50 per gj (50% above the floor price)	November 1 - December 31
		1,000 Gjpd	Participating Swap Cdn $6.50 per gj (max up to 90% above the floor price)	November 1 - December 31
		2,000 Gjpd	Participating Swap Cdn $6.75 per gj (max up to 90% above the floor price)	November 1 - December 31
		2,000 Gjpd	Participating Swap Cdn $7.00 per gj (max up to 85% above the floor price)	November 1 - December 31
		2,000 Gjpd	Participating Swap Cdn $7.50 per gj (max up to 100% above the floor price)	November 1 - December 31
		400 Gjpd	Participating Swap Cdn $7.75 per gj (23% above the floor price)	November 1 - December 31
2009	Crude Oil	125 Bpd	Participating Swap US $60.00 per bbl (60% above the floor price)	January 1 - December 31
		825 Bpd	Participating Swap US $62.50 per bbl (59.5% above the floor price)	January 1 - December 31
		400 Bpd	Participating Swap US $62.50 per bbl (max to 50% above the floor price)	January 1 - June 30
		1,500 Bpd	Participating Swap US $62.50 per bbl (62.6% above the floor price)	January 1 - June 30
		775 Bpd	Participating Swap US $62.50 per bbl (60.4% above the floor price)	July 1 - December 31
	Natural Gas	400 Gjpd	Participating Swap Cdn $7.75 per gj (23% above the floor price)	January 1 - December 31
		1,000 Gjpd	Participating Swap Cdn $6.50 per gj (50% above the floor price)	January 1 - March 31
		1,000 Gjpd	Participating Swap Cdn $6.50 per gj (max up to 90% above the floor price)	January 1 - March 31
		1,000 Gjpd	Participating Swap Cdn $6.75 per gj (51% above the floor price)	January 1 - March 31
		2,000 Gjpd	Participating Swap Cdn $6.75 per gj (max up to 90% above the floor price)	January 1 - March 31
		1,000 Gjpd	Participating Swap Cdn $7.00 per gj (max up to 85% above the floor price)	January 1 - March 31
		2,000 Gjpd	Participating Swap Cdn $7.00 per gj (max up to 85% above the floor price)	January 1 - March 31
		3,000 Gjpd	Participating Swap Cdn $7.50 per gj (max to 62% above the floor price)	January 1 - March 31

USOGP

Year	Product	Volume (Buy)Sell		Terms	Effective Period
2008	Crude Oil	125-325	Bpd	US $59.25 per bbl	January 1 - December 31
		325	Bpd	US $70.37 per bbl	January 1 - December 31
		790	Bpd	US $72.89 per bbl	January 1 - December 31
		425	Bpd	Participating Swap US $60.00 per bbl (max to 76% above the floor price)	January 1 - December 31
		2,650	Bpd	US $68.44 per bbl	January 1 - June 30
		250	Bpd	Costless Collar US $66.00 floor, US $69.25 ceiling	January 1 - June 30
		250	Bpd	Costless Collar US $66.00 floor, US $71.50 ceiling	January 1 - June 30
		250	Bpd	US $71.24 per bbl	July 1 - September 30
		2,500	Bpd	Participating Swap US $60.00 per bbl (max to 53.3% above the floor price)	July 1 - September 30
		250	Bpd	US $70.66 per bbl	July 1 - December 31
		250	Bpd	Participating Swap US $70.00 per bbl (61.8% above the floor price)	July 1 - December 31
		2,000	Bpd	Participating Swap US $60.00 per bbl (max to 59% above the floor price)	October 1 - December 31
		750	Bpd	US $70.49 per bbl	October 1 - December 31
		150	Bpd	Participating Swap US $60.00 per bbl (78% above the floor price)	January 1 - December 31
		250	Bpd	Participating Swap US $62.50 per bbl (57.5% above the floor price)	January 1 - December 31
		250	Bpd	Participating Swap US $65.00 per bbl (52% above the floor price)	January 1 - December 31
	Natural Gas	48,643	Mmbtu	US $8.01 per mmbtu [10]	January 1 - December 31
2009	Crude Oil	125 - 325	Bpd	US $59.25 per bbl	January 1 - December 31
		460	Bpd	US $69.95 per bbl	January 1 - December 31
		679	Bpd	US $71.38 per bbl	January 1 - December 31
		410	Bpd	Participating Swap US $60.00 per bbl (max to 67.99% above the floor price)	January 1 - December 31
		250	Bpd	Participating Swap US $62.50 per bbl (max to 67.25% above the floor price)	January 1 - December 31
		210	Bpd	Costless Collar US $60.00 floor, US $79.50 ceiling	January 1 - December 31
		250	Bpd	Participating Swap US $70.00 per bbl (61.8% above the floor price)	January 1 - December 31
		500	Bpd	Participating Swap US $60.00 per bbl (max to 55.5% above the floor price)	January 1 - September 30
		2,000	Bpd	Participating Swap US $60.00 per bbl (max to 59% above the floor price)	January 1 - September 30
		500	Bpd	US $70.92 per bbl	January 1 - March 31
		500	Bpd	US $72.25 per bbl	April 1 - June 30
		250	Bpd	US $72.47 per bbl	October 1 - December 31
		250	Bpd	Participating Swap US $60.00 per bbl (70% above the floor price)	October 1 - December 31
		500	Bpd	Participating Swap US $65.00 per bbl (54% above the floor price)	October 1 - December 31
		500	Bpd	Participating Swap US $65.00 per bbl (50% above the floor price)	October 1 - December 31
		250	Bpd	US $70.00 per bbl	December 1 - December 31
		425	Bpd	Participating Swap US $60.00 per bbl (61.45% above the floor price)	January 1 - December 31
	Natural Gas	44,071	Mmbtu	US $8.01 per mmbtu [10]	January 1 - December 31
2010	Crude Oil	609	Bpd	US $70.42 per bbl	January 1 - December 31
		500	Bpd	US $69.75 per bbl	January 1 - December 31
		933	Bpd	Participating Swap US $60.00 per bbl (max to 59.01% above the floor price)	January 1 - December 31
		250	Bpd	Participating Swap US $62.50 per bbl (56.20% above the floor price)	January 1 - December 31
		183	Bpd	Costless Collar US $60.00 floor, US $79.25 ceiling	January 1 - December 31
		183	Bpd	US $69.59 per bbl	January 1 - December 31
		250	Bpd	Participating Swap US $70.00 per bbl (61.8% above the floor price)	January 1 - March 31
		250	Bpd	Participating Swap US $60.00 per bbl (70% above the floor price)	January 1 - June 30
		500	Bpd	Participating Swap US $65.00 per bbl (50% above the floor price)	January 1 - June 30
		250	Bpd	US $72.47 per bbl	January 1 - June 30
		542	Bpd	US $72.05 per bbl	January 1 - July 31
		500	Bpd	Participating Swap US $70.00 per bbl (37.3% above the floor price)	April 1 - September 30
	Natural Gas	40,471	Mmbtu	US $8.01 per mmbtu [10]	January 1 - December 31
2011	Crude Oil	1,377	Bpd	Participating Swap US $60.00 per bbl (max to 53.11% above the floor price)	January 1 - December 31
		177	Bpd	Costless Collar US $60.00 floor, US $77.60 ceiling	January 1 - December 31
		177	Bpd	US $69.15 per bbl	January 1 - December 31
	Natural Gas	40,400	Mmbtu	US $8.01 per mmbtu [10]	January 1 - March 31

Midstream

Year	Product	Volume (Buy)Sell	Terms	Effective Period
2008	Crude Oil	2,250 Bpd	Costless Collar US $68.50 floor, US $73.72 ceiling	January 1 - December 31
		500 Bpd	Costless Collar US $64.00 floor, US $74.50 ceiling	January 1 - September 30
		500 Bpd	Costless Collar US $73.00 floor, US $80.00 ceiling	January 1 - June 30
		250 Bpd	US $65.60 per bbl	January 1 - December 31
		250 Bpd	US $66.65 per bbl	January 1 - December 31
		9,635 Bpd	Cdn $76.02 per bbl	January 1 - December 31
		(845) Bpd	US $74.64 per bbl [4]	January 1 - March 31
		(10,535) Bpd	US $86.93 per bbl [4]	January 1 - March 31
	Natural Gas	(75,767) Gjpd	Cdn $8.31 per gj	January 1 - December 31
	Foreign Exchange		Sell US $6,202,175 per month @ 1.1198 [5]	January 1 - December 31
			Sell US $1,107,166 per month @ 1.1035 [5]	January 1 - June 30
			Sell US $974,222 per month @ 1.1255 [5]	January 1 - September 30
	Propane	3,225 Bpd	US $1.5308 per gallon [6] [9]	January 1 - January 31
		1,206 Bpd	US $1.5382 per gallon [6] [9]	February 1 - February 29
		5,645 Bpd	US $1.2829 per gallon [6] [9]	January 1 - February 29
		850 Bpd	US $1.2487 per gallon [4] [6]	January 1 - March 31
		10,287 Bpd	US $1.4595 per gallon [4] [6]	January 1 - March 31
	Normal Butane	2,258 Bpd	US $1.8148 per gallon [7] [9]	January 1 - January 31
		2,230 Bpd	US $1.647 per gallon [4] [7]	January 1 - March 31
		150 Bpd	US $1.4325 per gallon [4] [7]	January 1 - March 31
	ISO Butane	150 Bpd	US $1.4453 per gallon [4] [8]	January 1 - March 31
		1,720 Bpd	US $1.6424 per gallon [4] [8]	January 1 - March 31
	Power	(20) MW/hpd	Cdn $76.43 per MW/h [12]	January 1 - December 31
2009	Crude Oil	2,500 Bpd	Costless Collar US $64.80 floor, US $69.36 ceiling	January 1 - December 31
		7,158 Bpd	Cdn $74.23 per bbl	January 1 - December 31
		250 Bpd	US $64.60 per bbl	January 1 - December 31
		250 Bpd	US $66.65 per bbl	January 1 - December 31
		500 Bpd	Costless Collar US $70.00 floor, US $79.00 ceiling	January 1 - June 30
		1,000 Bpd	Participating Swap US $63.13 per bbl (56% above the floor price)	July 1 - August 31
		598 Bpd	Participating Swap US $75.64 per bbl (55.7% above the floor price)	July 1 - November 30
		500 Bpd	Participating Swap Cdn $73.38 per bbl (48.9% above the floor price)	September 1 - November 30
	Natural Gas	(60,769) Gjpd	Cdn $8.14 per gj	January 1 - December 31
		(2,792) Gjpd	Participating Swap Cdn $7.73 per gj (39% below the ceiling price)	July 1 - November 30
		(2,810) Gjpd	Cdn $6.62 per gj	September 1 - October 31
		(2,810) Gjpd	Costless Collar Cdn $6.20 floor, Cdn $7.10 ceiling	September 1 - October 31
	Foreign Exchange		Sell US $6,699,029 per month @ 1.1113 [5]	January 1 - December 31
			Sell US $1,055,833 per month @ 1.099 [5]	January 1 - June 30
			Sell US $1,972,561 per month @ 1.0245	July 1 - August 31
			Sell US $596,166 per month @ 0.9815 [5]	July 1 - October 31
			Sell US $1,686,650 per month @ 0.9620 [5]	September 1 - October 31
			Sell US $1,163,100 per month @ 1.013 [5]	November 1 - November 30
2010	Crude Oil	1,500 Bpd	Costless Collar US $62.90 floor, US $67.48 ceiling	January 1 - December 31
		6,502 Bpd	Cdn $73.16 per bbl	January 1 - December 31
		250 Bpd	US $66.65 per bbl	January 1 - December 31
		500 Bpd	Participating Swap Cdn $61.50 per bbl (50% above the floor price)	July 1 - August 31
		376 Bpd	Participating Swap Cdn $70.91 per bbl (56% above the floor price)	July 1 - October 31
		820 Bpd	Participating Swap US $73.63 per bbl (51.8% above the floor price)	January 1 - November 30
	Natural Gas	(48,527) Gjpd	Cdn $7.89 per gj	January 1 - December 31
		(4,089) Gjpd	Participating Swap Cdn $7.62 per gj (31.3% below the ceiling price)	January 1 - November 30
	Foreign Exchange		Sell US $4,721,469 per month @ 1.1101 [5]	January 1 - December 31
			Sell US $582,821 per month @ 1.0159 [5]	January 1 - August 31
			Sell US $1,407,419 per month @ 0.9781 [5]	July 1 - August 31
			Sell US $587,903 per month @ 1.0165 [5]	July 1 - November 30
			Sell US $2,254,103 per month @ 0.9577 [5]	September 1 - October 31
			Sell US $1,750,992 per month @ 1.0176 [5]	September 1 - November 30

Midstream, cont'd.

Year	Product	(Buy)Sell	Terms	Effective Period
2011	Crude Oil	5,389 Bpd	Cdn $71.68 per bbl	January 1 - December 31
		250 Bpd	Participating Swap US $63.00 per bbl (64% above the floor price)	January 1 - December 31
		500 Bpd	Costless Collar US $65.00 floor, US $75.00 ceiling	January 1 - June 30
		2,000 Bpd	Costless Collar US $58.50 floor, US $72.69 ceiling	July 1 - September 30
	Natural Gas	(37,595) Gjpd	Cdn $7.31 per gj	January 1 - December 31
	Foreign Exchange		Sell US $980,417 per month @ 1.0805 [5]	January 1 - June 30
			Sell US $3,587,999 per month @ 1.0931 [5]	July 1 - September 30
			Sell US $479,063 per month @ 0.9725 [5]	January 1 - December 31
2012	Crude Oil	3,647 Bpd	Cdn $72.95 per bbl	January 1 - December 31
		1,141 Bpd	Participating Swap US $66.67 per bbl (59% above the floor price)	April 1 - December 31
		250 Bpd	Participating Swap Cdn $71.50 per bbl (50% above the floor price)	October 1 - December 31
	Natural Gas	(25,787) Gjpd	Cdn $7.23 per gj	January 1 - December 31
	Foreign Exchange		Sell US $1,437,986 per month @ 0.9657 [5]	July 1 - December 31
			Sell US $976,436 per month @ 0.9413 [5]	April 1 - October 31
			Sell US $1,634,227 per month @ 0.9832 [5]	October 1 - December 31
2013	Crude Oil	250 Bpd	Cdn $75.32 per bbl	January 1 - January 31
		750 Bpd	Participating Swap US $70.92 per bbl (50.6% above the floor price)	January 1 - January 31
		250 Bpd	Participating Swap Cdn $71.50 per bbl (50% above the floor price)	January 1 - January 31
	Natural Gas	(7,025) Gjpd	Cdn $7.19 per gj	January 1 - January 31
	Foreign Exchange		Sell US $1,651,990 per month @ 0.9832 [5]	January 1 - January 31

Corporate

Year	Product	(Buy)Sell	Terms	Effective Period
2008	Foreign Exchange		Sell US $9,000,000 @ .9701 [5.1]	January 25
			Sell US $3,000,000 @ 1.0105 [5.1]	February 25
	Interest Rate		Pay Fixed rate of 4.8852% - Receive 3M CAD BA on Cdn $50MM Notional [11]	January 1 - July 31

[1] The above table represents a number of transactions entered into over an extended period of time.

[2] Natural Gas contracts are settled against AECO monthly index.

[3] Crude Oil contracts are settled against NYMEX WTI calendar average

[4] Conversion of Crude Oil BTU positions to liquids.

[5] US dollar contracts settled against Bank of Canada noon rate average.

[5.1] US dollar cashflows sold forward.

[6] Propane contracts are settled against Belvieu C3 TET.

[7] Normal Butane contracts are settled against Belvieu NC4 NON-TET.

[8] ISO Butane contracts are settled against Belvieu IC4 NON-TET.

[9] Midstream inventory price stabilization contracts.

[10] Natural Gas contracts are settled against Natural Gas-Michcon Citygate Inside FERC.

[11] Settles quarterly against 3M CAD BA interest rate.

[12] Power contracts are settled monthly against the average hourly price of electricity as published by the AESO in $/MWh.

14. Cash reserve for future site reclamation

Provident established a cash reserve effective May 1, 2001 for future site reclamation expenditures relating to its Canadian oil and gas production. In accordance with the royalty agreement, Provident funds the reserve by paying $0.30 per barrel of oil equivalent produced on a 6:1 basis into a segregated cash account. Actual expenditures incurred are then funded from the cash in this account. The cash reserve was depleted in 2006 as actual expenditures exceeded contributions to the reserve.

15. Commitments

Provident has office lease commitments that extend through June 2022. Future minimum lease payments for the following five years are: 2008 - $8.6 million; 2009 - $10.6 million; 2010 - $10.5 million; 2011 - $10.4 million; and 2012 - $10.2 million.

In relation to the midstream services and marketing segment, Provident is committed to minimum lease payments under the terms of various rail tank car leases for the following five years: 2008 – $6.6 million; 2009 – $5.4 million; 2010 – $3.9 million; 2011 – $2.7 million, and 2012 – $1.3 million. Additionally, under an arrangement to use a third party interest in the Younger plant, Provident has a commitment to make payments calculated with reference to a number of variables including return on capital. Payments for the next five years are estimated as follows: 2008 - $4.3 million; 2009 - $4.0 million; 2010 - $3.8 million; 2011 – $4.1 million and 2012 - $4.3 million.

In relation to the United States oil and natural gas production segment, Provident's U.S. subsidiaries have performance obligations that are secured, in whole or in part, by surety bonds. These obligations primarily cover self-insurance and other programs where governmental organizations require such support. These surety bonds are issued by financial institutions and are required to be reimbursed by Provident's U.S. subsidiaries if drawn upon. At December 31, 2007, Provident's U.S. subsidiaries had obtained various surety bonds for U.S. $14.3 million (2006 – U.S. $4.9 million).

In relation to the United States oil and natural gas production segment, Provident leases certain property and equipment under operating leases. Future minimum lease payments for the following five years are as follows: 2008 – U.S. $0.9 million; 2009 – U.S. $0.8 million; 2010 – U.S. $0.7 million; 2011 – U.S. $0.7 million and 2012 – U.S. $0.7 million.

16. Subsequent event

In February 2008, the Trust announced that it has retained Morgan Stanley as financial advisor in connection with a strategic review process with the objective of selling the operations that comprise the United States oil and natural gas production (USOGP) segment. USOGP includes the Trust's interest in the MLP, the related general partner interest, as well as the Trust's interest in BreitBurn Energy Company L.P.

As at December 31, 2007 the Trust owned approximately 22 percent of the MLP and approximately 96 percent of BreitBurn Energy Company L.P. Pursuant to the announcement, the Trust will account for USOGP as discontinued operations beginning in the first quarter of 2008.

17. Segmented information

The Trust's business activities are conducted through three business segments: Canadian oil and natural gas production (COGP), United States oil and natural gas production (USOGP) and Midstream.

Oil and natural gas production in Canada and the United States includes exploitation, development and production of crude oil and natural gas reserves. Midstream includes processing, extraction, transportation, loading and storage of natural gas liquids, and marketing of natural gas liquids.

Geographically the Trust operates in Canada and the USA in the oil and gas production business segment. The geographic components have been presented for the oil and natural gas business as well as the Midstream business that operates in both Canada and the USA.

	Year ended December 31, 2007				
	Canadian Oil and Natural Gas Production	U.S. Oil and Natural Gas Production	Total Oil and Natural Gas Production	Midstream [1]	Total
Revenue					
Gross production revenue	$ 454,179	$ 278,414	$ 732,593	$ -	$ 732,593
Royalties	(87,046)	(31,654)	(118,700)	-	(118,700)
Product sales and service revenue	-	-	-	1,958,372	1,958,372
Realized gain (loss) on financial derivative instruments	1,728	(7,959)	(6,231)	(74,474)	(80,705)
	368,861	238,801	607,662	1,883,898	2,491,560
Expenses					
Cost of goods sold	-	11,143	11,143	1,594,639	1,605,782
Production, operating and maintenance	112,387	81,699	194,086	14,094	208,180
Transportation	8,193	3,102	11,295	16,825	28,120
Foreign exchange (gain) loss and other	(573)	-	(573)	3,996	3,423
General and administrative	27,102	45,188	72,290	28,669	100,959
	147,109	141,132	288,241	1,658,223	1,946,464
Earnings before interest, taxes, depletion, depreciation, accretion and other non-cash items	221,752	97,669	319,421	225,675	545,096
Other revenue					
Unrealized loss on financial derivative	(21,324)	(110,040)	(131,364)	(192,920)	(324,284)
Other expenses					
Depletion, depreciation and accretion	256,723	50,253	306,976	44,388	351,364
Interest on bank debt	11,055	7,439	18,494	33,166	51,660
Interest and accretion on convertible debentures	3,672	10,660	14,332	11,015	25,347
Amortization of deferred financing charges	-	-	-	-	-
Unrealized foreign exchange loss and other	779	2,593	3,372	-	3,372
Dilution gain	-	(260,324)	(260,324)	-	(260,324)
Non-cash unit based compensation	3,698	5,950	9,648	4,366	14,014
Internal management charge	(1,482)	1,482	-	-	-
Capital tax expense	3,762	-	3,762	-	3,762
Current and withholding tax (recovery) expense	(254)	10	(244)	6,606	6,362
Future income tax expense (recovery) [2]	(122,590)	58,843	(63,747)	94,234	30,487
	155,363	(123,094)	32,269	193,775	226,044
Non-controlling interest - USOGP	-	(35,666)	(35,666)	-	(35,666)
Non-controlling interest - exchangeables	-	-	-	-	-
Net income (loss) for the period	$ 45,065	$ 146,389	$ 191,454	$ (161,020)	$ 30,434

[1] Included in the Midstream segment is product sales and service revenue of $297.8 million associated with U.S. operations.

[2] Future income tax expense (recovery) includes a charge of $88.4 million relating to the enactment of Bill C-52, Budget Implementation Act 2007 by the Canadian government (see note 12).

	As at and for the year ended December 31, 2007				
	Canadian Oil and Natural Gas Production	U.S. Oil and Natural Gas Production	Total Oil and Natural Gas Production	Midstream	Total
Selected balance sheet items					
Capital assets					
Property, plant and equipment net	$ 1,773,209	$ 2,008,549	$ 3,781,758	$ 737,062	$ 4,518,820
Intangible assets	-	3,763	3,763	171,793	175,556
Goodwill	416,890	-	416,890	100,409	517,299
Capital expenditures					
Capital Expenditures	146,209	69,009	215,218	31,904	247,122
Corporate acquisitions	469,795	-	469,795	-	469,795
Oil and gas property acquisitions, net	13,050	1,015,803	1,028,853	-	1,028,853
Goodwill additions	85,946	-	85,946	-	85,946
Working capital					
Accounts receivable	75,292	79,457	154,749	262,813	417,562
Petroleum product inventory	-	5,636	5,636	84,638	90,274
Accounts payable and accrued liabilities	132,452	77,442	209,894	214,574	424,468
Long-term debt - revolving term credit facilities	230,999	368,836	599,835	692,997	1,292,832
Long-term debt - convertible debentures	35,129	115,925	151,054	105,386	256,440
Financial derivative instruments	$ 13,559	$ 102,859	$ 116,418	$ 261,587	$ 378,005

	Year ended December 31, 2006				
	Canadian Oil and Natural Gas Production	U.S. Oil and Natural Gas Production	Total Oil and Natural Gas Production	Midstream [1]	Total
Revenue					
Gross production revenue	$ 402,095	$ 176,160	$ 578,255	$ -	$ 578,255
Royalties	(81,225)	(17,315)	(98,540)	-	(98,540)
Product sales and service revenue	-	-	-	1,764,392	1,764,392
Realized gain (loss) on financial derivative instruments	4,371	(2,505)	1,866	(15,406)	(13,540)
	325,241	156,340	481,581	1,748,986	2,230,567
Expenses					
Cost of goods sold	-	-	-	1,471,171	1,471,171
Production, operating and maintenance	97,626	52,008	149,634	22,619	172,253
Transportation	5,114	-	5,114	14,672	19,786
Foreign exchange gain and other	(9)	-	(9)	(2,728)	(2,737)
Cash general and administrative	24,065	26,519	50,584	23,621	74,205
	126,796	78,527	205,323	1,529,355	1,734,678
Earnings before interest, taxes, depletion, depreciation, accretion and other non-cash items	198,445	77,813	276,258	219,631	495,889
Other revenue					
Unrealized gain (loss) on financial derivative instruments	17,299	7,735	25,034	(68,348)	(43,314)
Other expenses					
Depletion, depreciation and accretion	168,953	31,058	200,011	49,128	249,139
Interest on bank debt	10,082	4,861	14,943	19,723	34,666
Interest and accretion on convertible debentures	5,746	5,828	11,574	12,345	23,919
Amortization of deferred financing charges	956	786	1,742	2,112	3,854
Unrealized foreign exchange loss and other	-	-	-	418	418
Dilution gain	-	-	-	-	-
Non-cash unit based compensation	4,320	12,476	16,796	6,287	23,083
Internal management charge	(1,280)	1,280	-	-	-
Capital tax expense	1,314	-	1,314	-	1,314
Current and withholding tax expense	(2,124)	3,332	1,208	4,621	5,829
Future income tax expense (recovery)	(56,161)	20,297	(35,864)	1,548	(34,316)
	131,806	79,918	211,724	96,182	307,906
Non-controlling interest - USOGP	-	2,995	2,995	-	2,995
Non-controlling interest - exchangeables	485	37	522	232	754
Net income for the period	$ 83,453	$ 2,598	$ 86,051	$ 54,869	$ 140,920

[1] Included in the Midstream segment is product sales and service revenue of $332.9 million associated with U.S. operations.

	As at and for the year ended December 31, 2006				
	Canadian Oil and Natural Gas Production	U.S. Oil and Natural Gas Production	Total Oil and Natural Gas Production	Midstream	Total
Selected balance sheet items					
Capital assets					
Property, plant and equipment net	$ 1,211,112	$ 380,451	$ 1,591,563	$ 741,974	$ 2,333,537
Intangible assets	-	-	-	193,592	193,592
Goodwill	330,944	-	330,944	100,409	431,353
Capital expenditures					
Capital expenditures	70,088	54,337	124,425	66,008	190,433
Corporate acquisitions	-	-	-	1,036	1,036
Oil and gas property acquisitions, net	483,633	(2,008)	481,625	-	481,625
Goodwill additions	-	-	-	2,285	2,285
Working capital					
Accounts receivable	58,250	24,744	82,994	187,141	270,135
Petroleum product inventory	-	-	-	85,868	85,868
Accounts payable and accrued liabilities	86,305	52,626	138,931	156,072	295,003
Long-term debt - revolving term credit facilities	172,980	11,072	184,052	518,941	702,993
Long-term debt - convertible debentures	44,553	117,470	162,023	123,769	285,792
Financial derivative instruments (asset) liability	$ (7,520)	$ (8,417)	$ (15,937)	$ 68,795	52,858

18. Related party transactions

Included in accounts receivable as at December 31, 2007 is $32.8 million with related parties. Of this amount, $22.5 million represents a net receivable from Quicksilver, reflecting cash collections made on behalf of a subsidiary of the Trust in connection with the acquisition of assets from Quicksilver in the fourth quarter of 2007, net of advances. Quicksilver owns approximately 32 percent of the outstanding units of the MLP, a subsidiary of the Trust. The remaining $10.3 million relates to sales of crude oil by a subsidiary of the trust to a buyer whose Chairman of the Board and Chief Executive Officer is also a director of the general partner of the subsidiary of the Trust.

19. Reconciliation of financial statements to United States generally accepted accounting principles (U.S. GAAP)

The consolidated financial statements have been prepared in accordance with accounting principles generally accepted in Canada ("Canadian GAAP"). Any differences in accounting principles to U.S. GAAP as they pertain to the accompanying financial statements are not material except as described below. All adjustments are measurement differences. Disclosure items are not noted.

Consolidated Statements of Earnings - U.S. GAAP

For the year ended December 31, (Cdn $000s)		2007		2006
Net income as reported	$	30,434	$	140,920
Adjustments				
Depletion, depreciation and accretion (a)		72,485		12,146
Depletion, depreciation and accretion other (a)		(181,551)		(382,230)
General and administrative (d)		483		(483)
Future income tax recovery (a) (b)		23,625		110,898
Accretion on convertible debentures (e)		2,802		2,694
Non-controlling interest		(2,895)		754
Net loss – U.S. GAAP	$	(54,617)	$	(115,301)
Other comprehensive (loss) income		(26,000)		(509)
Comprehensive income (loss)		(80,617)		(115,810)
Net loss per unit - basic and diluted	$	(0.24)	$	(0.59)

Condensed Consolidated Balance Sheet

As at December 31, (Cdn$ 000s)	2007		2006	
	Canadian GAAP	U.S. GAAP	Canadian GAAP	U.S. GAAP
Assets				
Deferred financing charges (e)	$ -	$ 14,809	$ 12,351	$ 12,351
Property, plant and equipment (a)	4,518,820	3,983,181	2,333,537	1,906,964
Liabilities and unitholders' equity				
Current portion of convertible debentures (e)	19,198	19,931	-	-
Long-term debt - revolving term credit facilities (e)	1,292,832	1,300,645	702,993	702,993
Long-term debt - convertible debentures (e)	256,440	274,113	285,792	300,110
Other long-term liabilities (d)	20,759	20,759	16,305	16,788
Future income taxes (a) (b)	450,000	296,597	309,006	180,122
Non-controlling interests	1,100,136	1,103,031	81,111	81,111
Units subject to redemption (f)	-	2,308,273	-	2,317,196
Convertible debentures equity component (e)	18,213	-	18,522	-
Unitholders' contributions (f)	2,750,374	-	2,254,048	-
Accumulated other comprehensive (loss) income	(69,188)	(69,188)	(42,294)	(43,187)
Accumulated income (loss)	268,642	(927,762)	238,208	(1,044,840)
Accumulated cash distributions (f)	(1,260,177)	-	(926,825)	-

(a) Under the Canadian cost recovery ceiling test the recoverability of a cost centre is tested by comparing the carrying value of the cost centre to the sum of the undiscounted proved reserve cash flows expected from the cost centre using future price estimates. If the carrying value is not recoverable, the cost centre is written down to its fair value determined by comparing the future cash flows from the proved plus probable reserves discounted at the Trust's risk free interest rate. Any excess carrying value of the assets on the balance sheet above fair value would be recorded in depletion, depreciation and accretion expense as a permanent impairment. Under U.S. GAAP, companies utilizing the full cost method of accounting for oil and natural gas activities perform a ceiling test on each cost centre using discounted future net revenue from proved oil and natural gas reserves discounted at 10 percent. Prices used in the U.S. GAAP ceiling tests are those in effect at year-end. The amounts recorded for depletion and depreciation have been adjusted in the periods as a result of differences in write down amounts recorded pursuant to U.S. GAAP compared to Canadian GAAP.

In computing its consolidated net earnings for U.S. GAAP purposes, the Trust recorded additional depletion in 2007 of $181.6 million (2006 – $382.2 million) and a related future income tax recovery of $52.2 million (2006 - $114.7 million) as a result of the application of the ceiling test. These charges were not required under the Canadian GAAP ceiling tests.

(b) The Canadian liability method of accounting for income taxes in CICA handbook Section 3465 "Income taxes" is similar to the United States FAS 109, "Accounting for Income Taxes", which requires the recognition of deferred tax assets and liabilities for the expected future tax consequences of events that have been recognized in Provident's financial statements or tax returns. Pursuant to U.S. GAAP, enacted tax rates are used to calculate future taxes, whereas Canadian GAAP uses substantively enacted rates.

In July 2006, the FASB issued FIN 48, "Accounting for Uncertainty in Income Taxes". The interpretation creates a single model to address uncertainty in tax positions and clarifies the accounting for income taxes by prescribing the minimum recognition threshold a tax position is required to meet before being recognized in the financial statements. The statement also provides guidance on de-recognition, measurement, classification, interest and penalties, accounting in interim periods, disclosures and transitions as well as specifically scopes out accounting for contingencies. FIN 48 is effective for fiscal years beginning after December 15, 2006. The adoption of this statement has not resulted in a Canadian to U.S. GAAP difference.

(c) The consolidated statements of cash flows and operations and accumulated income are prepared in accordance with Canadian GAAP and conform in all material respects with U.S. GAAP except for the following;

(i) Canadian GAAP allows for the presentation of funds flow from operations in the consolidated statement of cash flows. This total cannot be presented under U.S. GAAP.

(ii) U.S. GAAP requires disclosure on the consolidated statement of operations when depreciation, depletion and amortization are excluded from cost of goods sold. This disclosure has not been noted on the face of the consolidated statement of operations.

(d) Under Canadian GAAP, Provident follows CICA handbook Section 3870 "Stock-based compensation and other stock-based payments" which provides for the presentation and measurement of cash-settled unit-based compensation as liabilities based on the intrinsic value each period. Under U.S. GAAP FAS 123R "Share-based payments", public entities are required to measure liability awards based on the award's fair value re-measured at each reporting date until the date of settlement. Compensation cost for each period is based on the change in the fair value of the units for each reporting period and is recognized over the vesting period.

(e) Under Canadian GAAP Provident applies EIC Abstract 164 "Convertible and other instruments with embedded derivatives" to account for the convertible debentures. Under U.S. GAAP, the convertible debentures are disclosed as long-term debt at their face value versus Canadian GAAP that requires discounting of the convertible debentures, accretion expense to represent the unwinding of the discounted convertible debentures and a value assigned within equity to the conversion feature component of the convertible debentures. In addition, U.S. GAAP requires debt issue costs to be reported as deferred charges on the consolidated balance sheet.

(f) Under U.S. GAAP, a redemption feature of equity instruments exercisable at the option of the holder requires that such equity be excluded from classification as permanent equity and be reported as temporary equity at the equity's redemption value. Changes in redemption value in the period (2007 - $505.1 million; 2006 - $188.6 million) are

recorded to accumulated earnings. Under Canadian GAAP, such equity instruments are considered to be permanent equity and are presented as unitholder's equity. The Trust's units have a redemption feature, which qualify them to be considered under this guidance.

Recent U.S. Accounting Pronouncements

Non-controlling interests in consolidated financial statements

In December 2007, the FASB issued FAS 160 "Non-controlling interests in Consolidated Financial Statements." FAS 160 requires the ownership interests in subsidiaries held by parties other than the parent be clearly presented in the consolidated balance sheet within equity, but separate from the parent's equity and the amount of consolidated net income attributable to the parent and the non-controlling interest be clearly identified and presented on the face of the consolidated statement of operations. Changes in the parent's ownership interest should be accounted for consistently as equity transactions. If a subsidiary is deconsolidated, any retained non-controlling equity investment in the former subsidiary should be initially recorded at fair value and the gain or loss on the deconsolidation of the subsidiary is measured using the fair value of any non-controlling equity investment rather than the carrying amount of the retained investment. This statement is effective for fiscal years, and interim periods, beginning on or after December 15, 2008. The application of this standard will impact how the Trust's balance sheet and statement of operations are presented.

Business combinations

In December 2007, the FASB revised FAS 141 "Business Combinations." FAS 141 establishes how an acquirer recognizes and measures in its financial statements the identifiable assets and liabilities as well as any non-controlling interest in the acquiree, how an acquirer should recognize and measure goodwill acquired in the business combination or a gain from a bargain purchase, and how an acquirer determines what information to disclose to enable users of the financial statements to evaluate the nature and financial effects of the business combination. The statement specifically addresses the treatment of acquisition costs separate from the acquisition as opposed to including them as part of the acquisition purchase price. This statement applies prospectively to business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2008. The adoption of this statement will impact any future business combination with an acquisition date after January 1, 2009.

The fair value option for financial assets and financial liabilities

In February 2007, the FASB issued FAS 159 "The Fair Value Option for Financial Assets and Financial Liabilities." FAS 159 permits entities to chose to measure eligible items at fair value at specified election dates. The entity would record gains and losses on items for which the fair value option has been elected in earnings at each subsequent reporting date. This statement is effective as of the beginning of an entity's first fiscal year that begins after November 15, 2007. The Trust does not expect the adoption of this statement to have a material impact on its financial statements.

Fair value measurement

In September 2006, the FASB issued FAS 157 "Fair value measurement." FAS 157 defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles and expands disclosures about fair value measurements. This statement does not require any new fair value measurements. Fair value is defined in this statement as the exchange price, which is the price in an orderly transaction between market participants to sell the asset or transfer the liability in the market in which the reporting entity would transact for the asset or liability, that is, the principal or most advantageous market for the asset or liability. The statement is effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods of those fiscal years. The Trust is currently evaluating the effect that this statement might have on the Trust's financial statements.

CORPORATE INFORMATION

OFFICERS

Thomas W. Buchanan, CA,
President and Chief Executive Officer

David I. Holm, B.Comm., LLB
Executive Vice President, Strategy, Finance, Business Development and Corporate Secretary

Daniel J. O'Byrne, P.Eng., MBA
Executive Vice President, Operations and Chief Operating Officer

Murray N. Buchanan, MBA
Co-President, Midstream Business Unit

Andrew G. Gruszecki, MBA
Co-President, Midstream Business Unit

Gary R. Kline
Senior Vice President, Commercial Development and Risk Management

Lynn M. Rannelli
Assistant Corporate Secretary

Cameron G. Vouri, P.Eng.
President, Canadian Oil and Gas Production Unit

Mark N. Walker, CMA
Senior Vice President, Finance and Chief Financial Officer

DIRECTORS

John B. Zaozirny, Q.C. [2]
Chairman
Calgary, Alberta

Thomas W. Buchanan, CA
Calgary, Alberta

Grant D. Billing, CA [2]
Calgary, Alberta

Hugh A. Fergusson, LLB [1][3]
Calgary, Alberta

Randall J. Findlay, P.Eng. [3]
Calgary, Alberta

Norman R. Gish, LLB [2]
Calgary, Alberta

Bruce R. Libin, Q.C. [1][3]
Calgary, Alberta

Dr. Robert W. Mitchell, Ph.D. [3]
Calgary, Alberta

Mike H. Shaikh, FCA [1]
Calgary, Alberta

Jeffrey T. Smith, P.Geol. [2][3]
Calgary, Alberta

Director Emeritus
Byron J. Seaman
Calgary, Alberta

[1] Member of Audit Committee

[2] Member of Governance, Human Resources and Compensation Committee

[3] Member of the Reserves, Operations and EH&S Committee

AUDITORS

PricewaterhouseCoopers LLP

BANKING SYNDICATE

Lead Syndicate Members (Canada)
National Bank of Canada
The Toronto Dominion Bank
Bank of Nova Scotia
Bank of Montreal

Lead Syndicate Members (U.S.)
Wells Fargo Bank

ENGINEERING CONSULTANTS

McDaniel & Associates Consultants Ltd.
Netherland, Sewell & Associates, Inc.
AJM Petroleum Consultants
Schlumberger Data & Consulting Services

LEGAL COUNSEL

Macleod Dixon LLP

TRUSTEE

Computershare Trust Company of Canada

ANNUAL GENERAL MEETING

The Annual Meeting of Provident Energy Trust will be held:
Date: May 8, 2008
Time: 3:00 p.m. MDT
Location: Sun Life Conference Centre
Mezzanine level
112-4th Ave. SW Calgary, Alberta
All unitholders are invited to attend.

STOCK EXCHANGE

Provident Energy Trust
Toronto Stock Exchange Units:
Trading Symbol – PVE.UN

New York Stock Exchange Units:
Trading Symbol – PVX

As a Canadian trust listed on the NYSE, Provident is not required to comply with most of the NYSE corporate governance standards, provided that it complies with Canadian corporate governance practices. In order to claim such an exemption, however, Provident must disclose the significant differences between its corporate governance practices and those required to be followed by U.S. domestic companies under the NYSE corporate governance standards. Provident's Statement of Significant Governance Differences can be found on Provident's website at www.providentenergy.com.

Debentures Trading Symbol
– PVE.DB.A
– PVE.DB.B
– PVE.DB.C
– PVE.DB.D

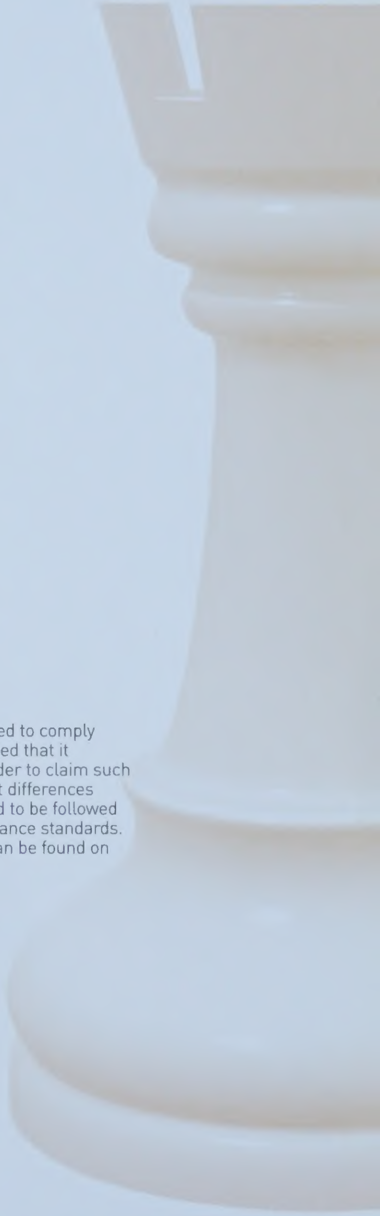
BreitBurn Energy Partners L.P.
NASDAQ Stock Exchange Units:
Trading Symbol – BBEP

HEAD OFFICE

2100, 250-2nd St. SW
Calgary, Alberta T2P 0C1
Tel: (403) 296-2233
Fax: (403) 294-0111
1-800-587-6299

FOR FURTHER INFORMATION:

Investor Relations
Tel: (403) 231-6710
www.providentenergy.com
info@providentenergy.com



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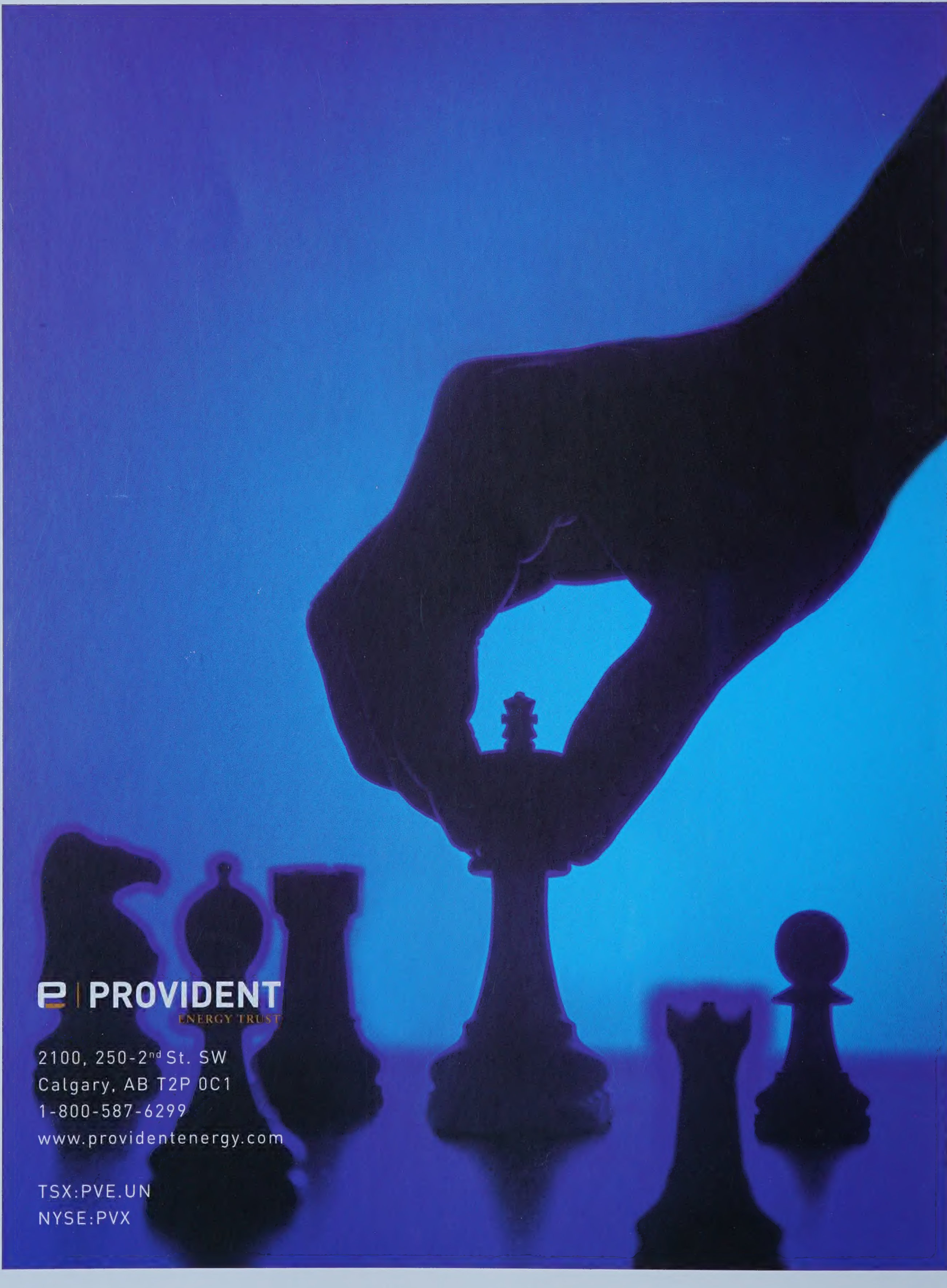
PROVIDENT
ENERGY TRUST
2100, 250-2nd St. SW
Calgary, AB T2P 0C1
1-800-587-6299
www.providentenergy.com
TSX:PVE.UN
NYSE:PVX